City of Colton

Electric Utility Department

2013 Integrated Resource Plan

September 2013

2013 INTEGRATED RESOURCE PLAN

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Chapter 1
2013 Integrated Resource Plan

Introduction

The Colton Electric Department (CED) faces new regulatory, legislative and financial challenges in 2013 that will impact operations and costs for years into the future. This "2013 Integrated Resource Plan" (IRP) will outline a strategy for dealing with some of the power supply issues that the CED faces and present alternative scenarios for resource procurement that are consistent with the current legislative and regulatory constraints. The IRP also identifies some of the regulatory requirements that impact day-to-day power supply operations of the utility.

An IRP takes into account both supply and demand side alternatives for meeting customer loads. Supply-side alternatives include the procurement of new generation and transmission resources, especially new renewable energy sources that meet California's renewable energy portfolio requirements. Demand-side alternatives include programs that reduce energy and capacity requirements during high-use periods or increase energy sales during low-load periods when the CED has surplus energy. Conservation programs, such as the CED's refrigerator replacement program and compact florescent bulb replacement program, attempt to reduce the need for additional supply side resources.

The CED believes that it is better for the community and CED itself to purchase energy from its own customers, in the form of reduced energy requirements, rather than purchasing additional generation resources.

Historically, the CED acquired new resources to meet the electricity needs of its ratepayers at the lowest possible cost without considering environmental and transmission constraints. But new state and federal environmental rules that went into effect in 2011 are going to reshape the CED over the next ten years. Complicating CED's planning efforts is that generation and transmission resources have lives of 20 to 50 years and decisions made today based upon current knowledge, legislation and technology, may be the "wrong" decision or a decision that results in higher costs ten or twenty years from now.

An IRP should be updated on an annual or bi-annual basis to address changes in the operating, legislative or regulatory environment. An IRP will change as the business and regulatory environment that the CED and its ratepayers live in changes. The IRP is a long-term planning document though with an emphasis on the first few years of operation. Today, many utilities are planning new transmission and generation resources that will not be operational until 2018 to 2025. Because of the long planning and permitting requirements of transmission and generation resources, utilities must begin the planning process years or decades in advance of need. CED is primarily concerned with identifying and acquiring new resources for the 2018 time period when CED's ownership in the San Juan Generating Station will end and CED has to acquire replacement capacity and energy.

An IRP is also a way for the City Council to specify its long-term goals for the Electric Department. The Colton City Council can direct the CED to acquire resources for different purposes, for example to minimize the cost of electricity for the City's ratepayers or be a greener utility than required by law or to maximize economic development within the City or to promote energy conservation. This IRP is developed to meet the following goals:

- Provide reliable energy to the residents and businesses in Colton;
- Minimize the cost of electricity service to Colton's ratepayers;
- Optimize the use of CED's generation and transmission resources;
- Meet all state and federal legislative and regulatory requirements;
- Develop demand-side programs to reduce energy use and costs by Colton's commercial and business customers;
- Encourage economic development within Colton by purchasing resources from local generators and developing demand-side programs that encourage businesses to locate and expand within Colton.

Because of the technical nature of many of the terms used throughout this IRP, a Glossary of Terms has been included in Appendix A.

Significant Changes from the 2012 Integrated Resource Plan

In 2012 there was uncertainty about the ultimate status of the San Juan Generating Station (SJGS). CED did not know what was going to be the resolution of the environmental litigation targeted at the SJGS. Now that the litigation has been resolved with CED and other owners agreeing to decommission two units at the plant and allowing the California utilities to leave SJGS, CED knows that it will have to procure replacement capacity and energy. By 2018 CED will have to replace over 225,000 MWh of energy and 30 MW of capacity, in addition to any load growth between 2013 and 2018.

CED will also have to come in compliance with California's renewable portfolio requirements so most of the replacement capacity and energy will be from renewable sources.

CED will begin bringing small solar PV generation resources online in 2014 as it begins meeting renewable standards. However, in the next year, CED will have to commit to significant new generation sources that will begin coming online in 2017 and 2018.

CED will also have to determine the potential risk that it is willing to accept associated with the decommissioning of two units of SJGS. With the units planned to be shut down by December 31, 2017, the project owners are not going to commit significant funds for operation and maintenance (O&M) expenses after 2016. So it is possible that the unit will be shut down prior to the scheduled date. This would require CED to acquire replacement capacity and energy to meet its retail load obligations at additional cost.

Current Energy Resources

Since the early 1980's, Colton has invested in acquiring generation and transmission resources. Due partially to its small size that makes it difficult for CED to purchase an entire generation project, CED has generally participated with other municipal utilities in acquiring resources through the Southern California Public Power Authority (SCPPA), a joint-power agency[1]. SCPPA identifies potential resources for ownership through an extensive RFP process and the member cities can choose which, if any, of the projects they wish to participate in and the capacity amount. CED can also issue its own RFPs or negotiate with generators outside of the SCPPA RFP process.

Colton currently has ownership or ownership-like rights in the following generation resources:

NAME	CAPACITY
San Juan Generating Station, unit 3	30 MW
Palo Verde Nuclear Generating Station	2 MW
Magnolia Generating Station	10 MW
Hoover Generating Station	3 MW
Agua Mansa Power Plant	43 MW
Iberdola Wind Project	1 MW
Colton Landfill	2 MW
TOTAL	91 MW

In addition, CED has an energy swap agreement with the City of Anaheim under which Colton purchases renewable energy from small hydroelectric generation facilities in southern California and then sells the energy to the City of Anaheim as brown energy while keeping the renewable attributes to help meet RPS requirements.

The San Juan Generating Station is the CED's second biggest resource in terms of capacity and by far the largest energy source supplying approximately two-thirds of CED's annual energy requirements.

Forecast of Demand and Energy Requirements

CED has prepared a forecast of monthly peak demand and energy requirements for the period 2012 – 2016. The forecast illustrates the impact on CED's demand and energy sales since the beginning of the current economic downturn and suggests that economic activity in the San Bernardino area is improving and with it, electric sales and revenues for the CED.

There is still significant concern about the strength of the economic upturn. Local economic activity is still being supported by federal monetary policy and the impacts of fiscal policy are dragging at the economic recovery.

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[1] In addition to Colton, SCPPA participants include the Cities of Los Angeles, Glendale, Burbank, Pasadena, Azusa, Banning, Riverside, Anaheim, Cerritos and the Imperial Irrigation District.

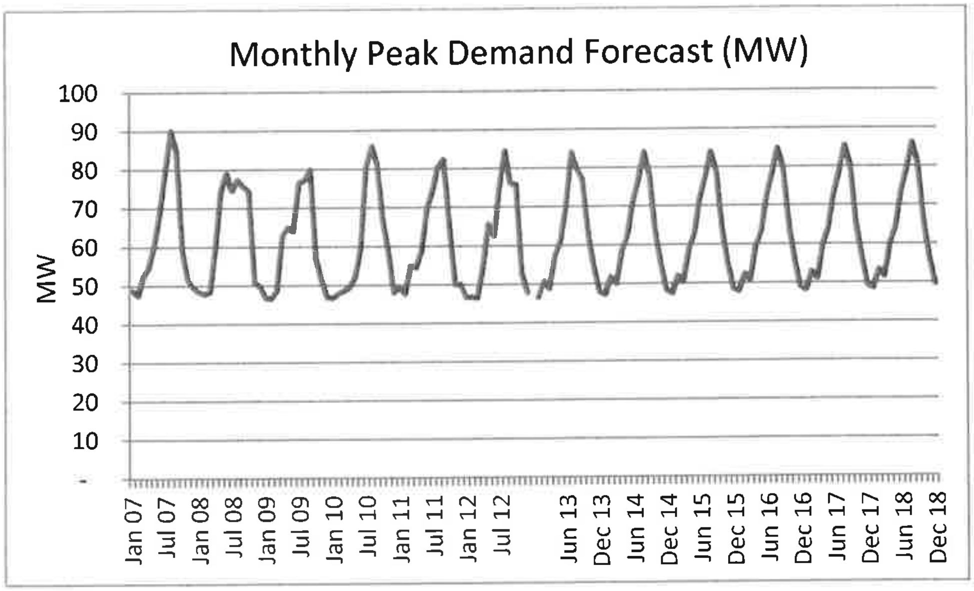

Figure 1.1 Forecast of Monthly Peak Demand (MW)

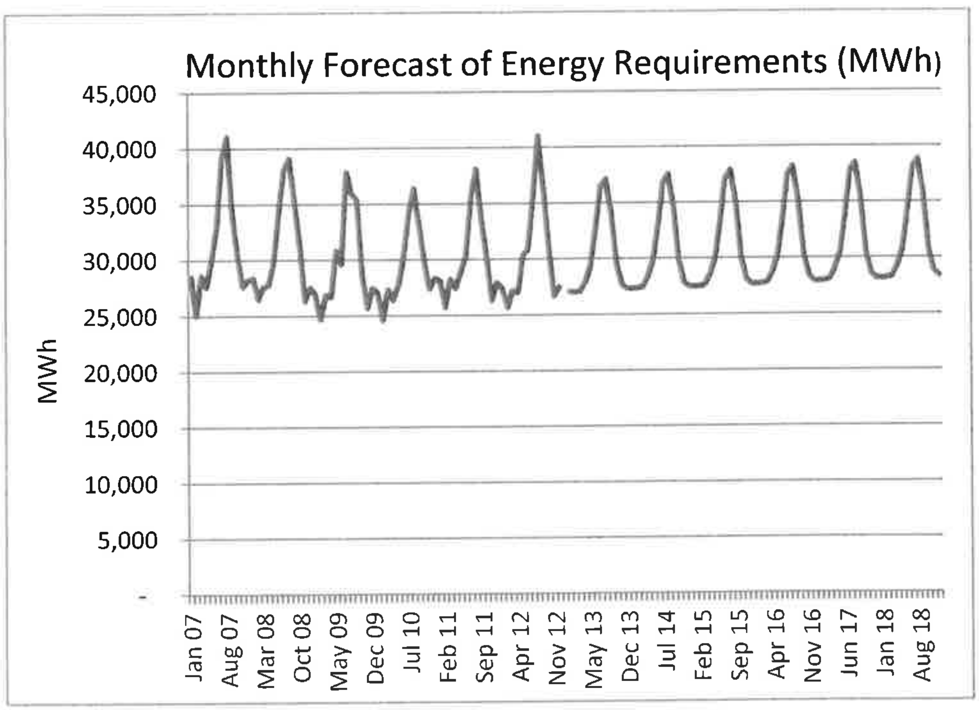

Figure 2.2 Forecast of Monthly Energy Requirements (MWh)

Legislative and Regulatory Requirements

For the past twelve years, state and federal agencies have been crafting rules for greenhouse gas reduction and environmental regulations, including renewable energy standards, and implementing new regulations intended to improve the reliability of the bulk power grid.

From the CED's viewpoint, the regulations having the greatest initial impact on costs include:

- California's AB 32 and SBX1-2;
- Federal Clean-Air Act;
- Implementation of the California Independent System Operator's Market Re-design and Technology Update including the new capacity market;
- New flexible capacity requirements.

California Legislation and Regulation

California legislators have passed a number of bills that impact the operations and power supply costs of CED. The specific new legislation potentially having the greatest impact on CED is AB 32, the California Global Warming Solutions Act.

AB 32 requires California utilities to reduce greenhouse gases associated with the generation of electricity. AB 32 also requires utilities, in conjunction with California's renewable portfolio standard requirements, codified in SB 2[2], to acquire renewable resources that have only a fraction of the greenhouse gases of traditional fossil-fuel fired generation.

Some of the major impacts of AB 32 include:

- Cap and trade emission allowance trading beginning in November 2012;
- Annual inventory of utility greenhouse gas emissions;
- Restrictions on the amount of new coal fired generation being imported into California;

In addition, AB 32 requires electric Load Serving Entities (LSEs) to acquire 20 percent of their retail load requirements from renewable sources for the period 2011-2013, increasing to 25 percent by 2016 and to 33 percent by 2020[3]. These minimum renewable energy standards are called the renewable portfolio standards (RPS) requirements. Newly proposed (but not yet adopted) regulations raise renewable standards to 50 percent by 2030.

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[2] Sometimes called SBX-1 2, referring to session 1 of the special legislation in the 2012 session in which it was passed

[3] In May 2013 the CEC also adopted intermediate standards governing procurement between 2016 and 2020.

The RPS requirements were also legislated in SB 2 to reinforce the importance to the state of emission reduction and to remove the perception that the new regulations were introduced by a regulatory agency rather than the state legislature.

At this time, CED is not meeting its RPS requirements. 2011 renewable energy purchases were only around 6 percent, well below the 20 percent average for the first compliance period. However, CED can purchase renewable energy credits in 2012 to meet a small portion of its 2011 obligations. Increasing the amount of renewable energy in CED's portfolio is one of the major tasks facing the utility going forward.

Cap and Trade

The Cap and Trade (C&T) program for electric utilities has begun with the first auction of emission allowances in November 2012. CED has implemented C&T requirements into its daily power resource trading activities.

In 2009, CED was allocated Emission Allowances (EAs) from the California Air Quality Management District (CARB) equal to its then estimated emissions.

CED does not have sufficient freely allocated EAs to offset all its emissions. An analysis of CED's emissions suggests that CED is approximately 30,000 to 40,000 EAs short (or about 15 percent) of actual emissions and will have to purchase these through the auction process. At current prices, acquiring these allowances will cost about $600,000 annually.

California Independent System Operator (CAISO) and Market Re-Design

Prior to 2002, a utility could acquire a generation resource and transmission and schedule the energy into a balancing area (BA). The BA operator (Southern California Edison (SCE) in Colton's case) would sell energy to the utility if the utility's schedule was insufficient to meet its retail load or purchase energy if the utility scheduled too much energy into the BA. Utilities operated under a strict set of rules about the accuracy of their hourly forecast and scheduling operations and violating these rules resulted in financial penalties from the BA.

Beginning in 2004, the CAISO assumed operational control of most of the transmission owned by California utilities.[4] The CAISO schedules and dispatches all the generation to meet load over CAISO controlled transmission. The CAISO also provides all ancillary services[5] necessary to meet the moment to moment fluctuations in energy demand.

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[4] The municipal utilities of Los Angeles, Sacramento, Modesto Irrigation District, Imperial Irrigation District and Turlock Irrigation District do not participate in the CAISO market directly.

[5] Electricity demand varies on a moment to moment basis and ancillary services meet these instantaneous fluctuations in demand by increasing or decreasing energy generation.

The CAISO is a "closed" market. Utilities purchase all their energy from the CAISO even if they have generation resources and utilities sell all their generation to the CAISO. Utilities (like the CED) that own or control their own generation resources can submit energy supply bids to the CAISO indicating the conditions under which they are willing to operate. Whether or not the resource actually runs depends upon the contract terms, pricing and locational factors. But the utility is guaranteed that its costs are no greater than the cost of its submitted schedule[6].

The CED has contracted with Shell Energy to be its schedule coordinator (SC) to submit its daily load forecasts and generation schedules to the CAISO and to handle all daily interactions with the CAISO. The SC takes into account a variety of contractual and operating constraints on how to bid resources to the CAISO. The CED does not currently have the in-house staff to perform this service.

The CAISO market is only four years old and still evolving to meet new issues. At this time, CED is not prepared to take full advantage of some of the operational and transmission opportunities available to it in the new market, especially with the Agua Mansa Power Plant, because CED has more baseload generation than required for load serving purposes.

Understanding the MRTU market rules is especially important in determining the best way to use Colton's Agua Mansa Power Plant (AMPP), the city-owned 49 MW gas-fired peaking plant (43 MW net) located within the City of Colton. AMPP provides capacity and energy to the CAISO controlled grid and acts as a physical hedge against power price spikes for the CED.

The permanent closure of the San Onofre Nuclear Generating Station (SONGS) in 2013 has resulted in a short-term capacity shortage in southern California. The CAISO is developing new capacity rules, partially due to problems integrating intermittent resources into the grid and partially to help mitigate the impact of SONGS that need to be addressed by CED. At this time, CED does not know how it will be affected by the proposed changes in the capacity market other than being required to make resource acquisition decisions earlier than in the past.

The greatest concern to CED is that the CEC and CAISO adopt a proposed flexible capacity mechanism that requires utilities to commit to capacity resources three years in advance of need with the CAISO operating a capacity auction to acquire new capacity on behalf of entities that are short. This would require CED to make all its resource decisions for 2018 by 2015 to avoid having the CAISO start procuring capacity for the CED and obligating CED to pay for any capacity procured on its behalf.

[6] There is a caveat dealing with transmission access. So long as the transmission lines have sufficient capacity, costs will not exceed the cost of meeting load with owned generation. However, if a utility does not have sufficient congestion revenue rights, then its costs can increase.

Cap and Trade and MRTU

One effect of the C&T regulations is that beginning January 1, 2013 wholesale prices rose somewhat due to price of emission allowances. The price impact was due to generators and POUs that are in the CAISO that cannot use freely allocated emission allowances to offset the cost of GHG emissions. If an entity receives (free) allocated EAs, and can use them to offset emissions associated with retail purchases or sales, the value of the EAs should mitigate the price increases in the MRTU market, assuming the entity received the proper amount of EAs. If an entity did not receive the necessary amount of EAs to cover emissions, then their power supply costs will likely rise.

It will be difficult to precisely determine the effect on the wholesale energy market of the cap and trade rules. However, a range of impacts can be estimated by using a price of $16 per EA. Coal generation costs would rise by $16/MWh based upon emissions of 1 ton per MWh, while costs of natural gas generation would rise by $8/MWh based upon emissions of 0.5 tons/MWh. Generally, as a result of both the SONGS closure and beginning of cap and trade, energy prices have increased about $5/MWh – but other factors could be impacting energy costs making it difficult to determine the impact of cap and trade on market prices.

Federal Clean-Air Act

The Clean-Air Act was enacted in 1990. The Act defines the Environmental Protection Agency's (EPA's) responsibilities for protecting and improving the nation's air quality.

San Juan Generating Station (SJGS) is owned by SCPPA, PNM, APS and a number of smaller participants. CED has a 30 MW entitlement in San Juan Unit 3 (SJ3), one of 4 units at the Station. SJ3 is CED's largest generation resource, providing approximately 65 percent of CED's annual electricity requirements.

Because of its size (1,800 MW) and location near the mouth of the Grand Canyon and initial lack of pollution control equipment San Juan has been a concern to environmentalists since the 1980's.

In 2006, Public Service Company of New Mexico (PNM), the plant majority owner and operator on behalf of the participants, began a $320 million emission reduction program that included bag houses and emission reduction equipment that significantly reduced particulate emissions including mercury, nitrogen oxides, sulfur dioxides and particulates.

The environmental upgrade was completed in 2009. But, in 2010, as a result of additional lawsuits filed by environmental groups, EPA proposed additional environmental upgrades that would require SJGS to meet a nitrogen oxide emission rate of 0.05 lb/mmbtu[7] through the use of selective catalytic reduction, the best available retrofit technology (BART) that would reduce emissions by more than 80 percent.

[7] Mmbtu is one million btu's, a measure of heat content of fuels.

In late 2012, PNM and the EPA reached agreement to shut-down 2 units at San Juan no later than December 31, 2017. The California participants would be allowed to shut-down their units (or trade their capacity shares in units that would continue to operate for shares in units that would be shut-down) and exit the project.

While an agreement between the participants and EPA has been reached, the negotiations between the various parties on cost responsibilities are still ongoing. Entities that are leaving the plant are trying to limit their long-term exposure to future environmental or decommissioning costs while the remaining plant owners are hesitant about possibly assuming unanticipated costs that should belong to the departing owners.

Risk Management

Risk management identifies the dollar amount at risk of loss due to changes in fuel prices or unanticipated outages of generation resources and recommends alternative actions to minimize this risk. The CED has not historically had significant risk management policies to prevent against over-purchasing natural gas or electric generation resources.

There are a number of ways to define and measure risk but a common risk metric is the Value at Risk (VAR).

The CED has adopted a risk management policy that attempts to limit the CED's VAR and requires multiple approvals for long-term firm power supply purchases to insure adequate oversight of purchases that impact the financial stability of the CED.

The major points of CED's Risk Management Policy include:

- Review by Colton's Management Services Director of any new long-term power supply purchases or firm power supply purchase exceeding $500,000 in any single month;
- Maximum monthly limits on CED's power supply VAR (or a limit on how much CED's energy costs can increase month to month);
- Required review and verification of CED's monthly energy balance;
- Review of monthly congestion costs and CRR status;
- Review of monthly costs of EA's and verification that CED has sufficient EAs to cover expected annual emissions.

Summary and Recommendations

The following recommendations are presented to lower CED's annual power supply costs and to bring CED into compliance with current RPS requirements.

- CED must acquire approximately 15 MW of intermittent renewable resources (solar PV or wind) by 2018 and 10-13 MW of baseload renewable resources (biogas, biomass or geothermal generation) by 2018. This generation capacity is needed to both meet CED's retail load requirements and meet RPS requirements;

- CED will require a 10 MW baseload resource in 2018 (in addition to the renewable resources identified above) to meet load requirements. CED should begin the CEQA process and CAISO interconnection process by December 2013 if the plant is needed by 2017;
- CED will not meet California's RPS requirements for the first compliance period (2011-2013). CED anticipates having to defend its failure to meet RPS requirements before the CEC and ARB.
- CED has begun the process of acquiring up to 11 MW of solar PV generation south of the Colton Landfill and other sites within Colton and surrounding areas. CED will still require a small amount of peaking energy in addition to the renewable resources identified in this IRP. CED believes that it will be in full compliance with RPS requirements by 2018.
- CED personnel need additional training in managing transmission costs. Congestion costs have been a major cost to CED since 2008.
- CED has adopted a Risk Management Plan that includes evaluating medium and long-term power purchases, renewable energy and emission allowances. CED's Risk Management Plan has been approved by the City.

If the above recommendations are followed, including additional recommendations that are being developed on CED's transmission resources, CED can maintain current rate levels and potentially lower total power supply costs and reduce operating and regulatory risk.

Chapter 2
Demand and Energy Requirements

Introduction

An IRP begins with a forecast of future demand and energy requirements. The demand forecast identifies how much generation capacity CED must have on a monthly basis for the next five years. The energy forecast identifies monthly energy needs and provides an estimate of monthly electricity sales to retail customers. The energy forecast also provides necessary information on the daily pattern of energy use needed to ensure that the appropriate mix of generation resources is acquired.

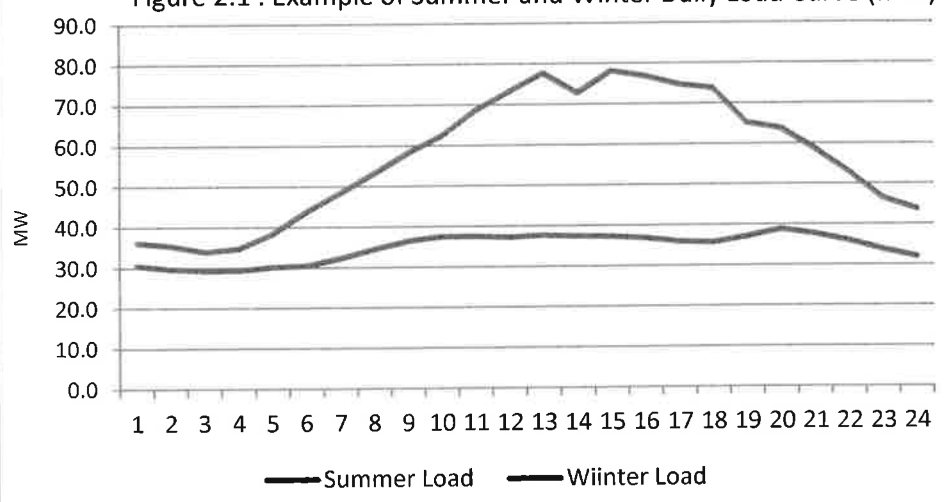
Energy Forecast

Colton is a summer peaking utility with energy use increasing in the summer by as much as 50 percent compared to the winter months. During the non-summer months, Colton's energy use is around 25,000 MWh per month while in the three summer months energy use increases to around 39,000 MWh primarily as a result of increased air conditioning use.

Colton does not appear to have much winter heating load although extreme cold temperature does result in a small increase in energy demand likely due to electric space heaters.

The following figure illustrates how Colton's daily load varies between the summer and winter months.

Figure 2.1 : Example of Summer and Winter Daily Load Curve (MW)



During the winter months, load begins to build as people wake up around 0430 and prepare for work in the morning. Then the commercial industrial load begins around 0700 and stays fairly constant until around 1600 each afternoon and then begins to drop as companies start shutting down. As people arrive home, the early evening residential load causes a peak around 1900 and then load begins to decline throughout the evening before the cycle begins again the next day.

During the summer the same pattern is followed except the additional air conditioning load begins around 0700 as firms begin pre-cooling in anticipation of people arriving for work and then continues to rise during the day until around 1600 when temperatures begin moderating and people leave work. At around 1800 or 1900 there is a slight increase in energy use due to residential lighting and air conditioning loads and then demand begins to decline as people begin going to bed around 2000.

While there is generally some increase in local economic activity during the summer months, most of Colton's additional summer load is due solely to increased air conditioning use.

The above load profiles help illustrate two key points. First, Colton requires about 28 to 30 MW of baseload energy on an annual basis and secondly, Colton's summer peaks are greater than its winter peaks and require more seasonal generation capacity to meet the increased demand.

The daily load profiles also suggest that the primary drivers of electricity demand in Colton are temperature and economic activity.

High temperature results in increased air conditioning use, while economic activity (measured in terms of total employment in the Riverside-San Bernardino-Ontario SMSA) affects the number of commercial/industrial businesses with the City.

The relationship between monthly energy use, temperature and economic activity was analyzed to determine if a statistically valid relationship could be identified and if this relationship could be used to forecast future monthly energy requirements.

A simple regression analysis was performed on the data and the following equation was determined to be a good predictor of monthly energy use:

Monthly Energy Requirements = f(civilian employment, degree days heating and degree days cooling)[8]

Degree days cooling (DDC) is the sum of ((Daily High Temperature + Daily Low Temperature)/2) – 65. DDC is a measure of the daily heat build-up that results in air conditioning use. Conversely, degree days heating is equal to:

65 – ((Daily High Temperature + Daily Low Temperature)/2)

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[8] The regression specification is:	*Coefficients*	*Standard Error*	*t Stat*
Intercept	13669.11854	3854.679995	3.54611
Employment	0.011112269	0.003238412	3.431394
DDC	23.78236609	1.659614166	14.33006
DDH	1.095105476	1.919996722	0.570368

Neither DDC or DDH can be negative, so if the average daily temperature is below 65 degrees, the DDC is 0, while if DDH is greater than 65 degrees, then DDH is 0.

Civilian Employment in the Riverside-San Bernardino-Ontario SMSA was chosen as a measure of economic activity and because the California State Department of Finance provides a forecast of Civilian Employment for 3 years into the future as part of the State Economic Forecasting Project and data is available on quarterly basis.

The following figure illustrates how the modeling performed in explaining monthly energy requirements and the 2012, 2013 and 2014 forecast.

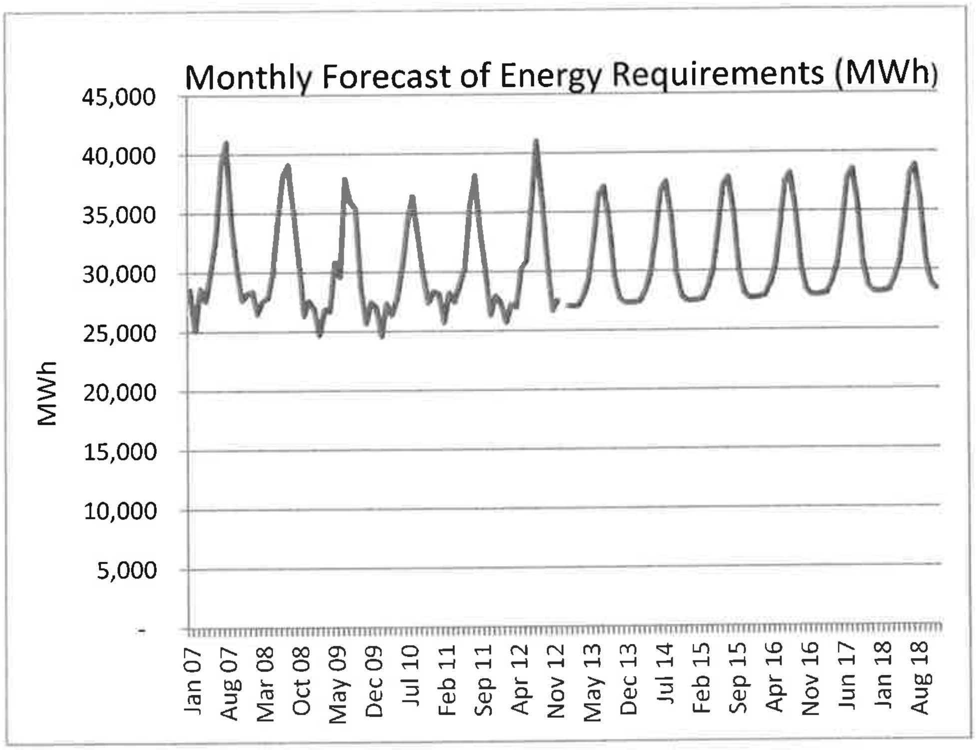


Figure 2.2: Forecasted Monthly Energy Requirements

In general, the model very slightly under-forecasts winter energy requirements (by about 2 percent) but otherwise tracks monthly energy use accurately.

The above figure also helps show what happened to CED's financial position in 2008, 2009 and 2010. In FY 2007/08, CED's energy requirements[9] were slightly greater than 375,000 MWh. With the beginning of the current "great recession," requirements have declined to slightly more than 354,000 MWh in FY 2009/10, a 5.5 percent reduction. 2010/2011 requirements improved very slightly in 2010/11 to 357,800

[9] Energy requirements differ from retail sales in that energy requirements are equal to energy sales plus unaccounted for energy. Unaccounted for energy includes losses and unbilled energy. Unaccounted for energy generally is around 5.5% of sales.

MWh. This reduction in energy requirements as a result of regional and national economic conditions has reduced CED's annual revenues by almost $2,000,000 (at current rate levels).

The forecast shows a slight improvement in energy requirements and sales from the 2011/12 levels to 368,800 MWh in 2012/13 and then to 371,400 MWh in 2013/14. This is a slightly lower forecast (by about 0.33 percent) than last year primarily due to a slightly reduced forecast of growth in California economic activity in 2013. The Department of Finance has slightly lowered its growth rate for California employment, reflecting the difficulty that the economy has had creating new jobs and the effects of budget cuts at the federal level impacting jobs throughout the nation.

Peak Demand Forecast

Forecasting peak demand is more difficult that forecasting monthly energy requirements. Monthly energy requirements are the average of all the hourly demands during the month. Forecasting peak demand requires picking the single greatest interval during the month, in a small system which is impacted by changes in weather and where even a large motor turning on or off can cause the monthly peak demand to change.

Peak demand forecasts are necessary for the CAISO to determine how much generating capacity a utility is required to acquire. Demand forecasts are required by regulatory and operating bodies such as the California Energy Commission (CEC) which verifies CED's demand forecast and the Western Area Power Administration (Western) as a condition of receiving Hoover Dam capacity and energy.

In the CAISO market, LSE's are required to have generation capacity equal to 115 percent of their monthly forecasted peak demand. Because LSE's recognize that having excess generating capacity is expensive and might attempt to under-forecast demand, the CEC verifies any peak demand forecast on an annual basis to establish monthly capacity obligations. If the CEC determines that peak demand forecasts are incorrect, they will issue a revised peak demand forecast that must be used to determine the monthly capacity obligation.

Because of the difficulty in forecasting hourly peak demand with monthly statistical models, CED uses a capacity factor model. The capacity factor is defined as:

Capacity Factor = (Monthly Energy Requirements) / (Peak Demand * Days in Month * 24 hours per day)

The average monthly capacity factor for the past six years (2007 through 2013) was calculated and then a monthly peak demand forecast was calculated based upon monthly forecasted energy requirements.

The monthly peak demand forecast is shown in Figure 2.3 below:

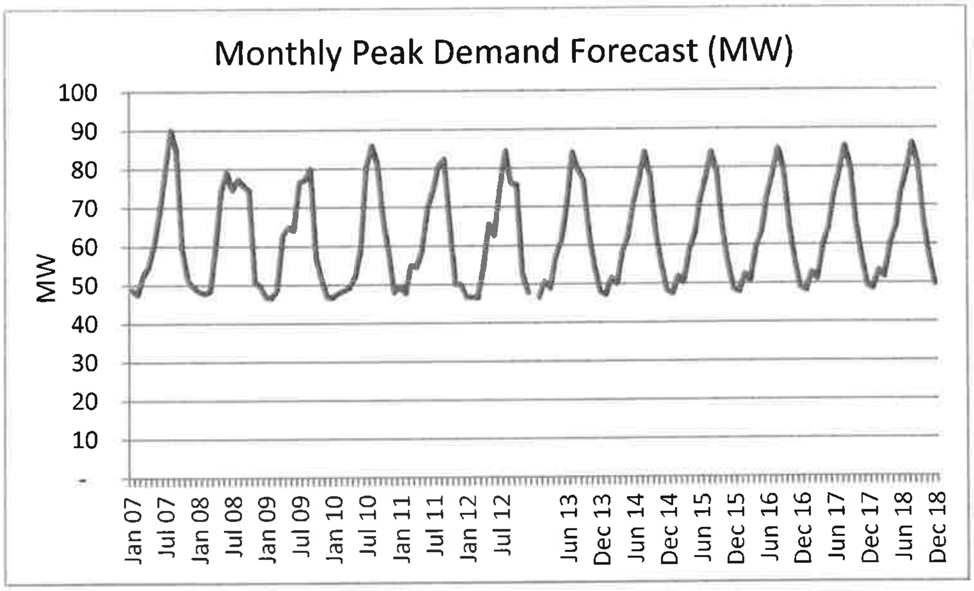


Figure 2.3: Monthly Peak Demand Forecast

The peak demand forecast shows the decline in monthly peak demands since the 2007 system peak and then forecasts a very slight increase from 2012 levels as the economy improves. These monthly forecasted peak demands will be used to determine the CED's monthly capacity obligations in the future.

The monthly demand and energy forecasts for 2013 – 2018 are shown in Appendix B.

Chapter 3
Existing Resources

Introduction

The CED currently has approximately 90 MW of capacity resources able to generate about 400,000 MWh annually at full capacity excluding the energy from the AMPP that is a peaking unit designed to operate at lower capacity factors when power prices are high. This compares to CED's annual energy requirements of around 360,000 MWh. The following chapter discusses each of the different resources.

While CED currently has enough generation to meet its retail load requirements, the planned decommissioning of SJ3 in 2018 will result in CED having to acquire new generation resources.

SCPPA

CED does not own or operate any generating or bulk power transmission facilities except the Agua Mansa Power Plant. All of CED's power supply contracts are either through SCPPA or power purchase agreements with small generators within the City.

SCPPA is a joint-power agency that enters into power purchase and transmission wheeling agreements or owns generation and transmission resources on behalf of its member municipal utilities. SCPPA has no retail load obligations.

Small utilities (such as CED) would have difficulty in acquiring financing to participate in large generation projects or transmission contracts. SCPPA enters into the agreements on behalf of its members and then guarantees any monthly financing or operating expenses by entering into power purchase agreements with member agencies. Each of SCPPA's projects has different participating utilities and only the utilities participating in a project are liable for costs associated with any project.

San Juan Generating Station, Unit 3

San Juan Generating Station (SJGS) is comprised of four units, each with a total net output of almost 1,800 MW. Project participants include:

Units 1 and 2
- PNM: 50 percent
- Tucson Electric Power: 50 percent

Unit 3
- PNM: 50 percent
- Southern California Public Power Authority: 41.8 percent
- Tri-State Generation and Transmission Association: 8.2 percent

Unit 4
- PNM: 38.5 percent
- MSR Public Power Agency: 28.8 percent
- City of Anaheim, Calif.: 10 percent
- City of Farmington: 8.5 percent

- Los Alamos County: 7.2 percent
- Utah Associated Municipal Power Systems: 7 percent

CED's 30 MW entitlement in Unit 3 is through SCPPA's 41.8 percent ownership in Unit 3.

The SJGS is located in the four corners region, near the borders of New Mexico, Arizona, Colorado and Utah.

As the part owner of SJ3, SCPPA administers the project on behalf of its participants, the Cities of Azusa, Banning, Colton, Glendale and the Imperial Irrigation District (IID).

SCPPA purchased its share of SJ3 in 1981 when the federal government was discouraging the use of natural gas for fear of dwindling supply and expected long-term shortages of residential heating fuel. In fact, the 1977 Fuel Use Act prohibited the construction of new natural gas generation facilities. As a result, southern California municipal utilities purchased coal projects that provided long-term, stable sources of electricity at relatively low prices.

SJ3 is CED's largest single resource and generates about 250,000 MWh of energy in normal years or approximately two-thirds of Colton's energy requirements.

Energy from SJ3 is delivered to the Westwing substation near Phoenix under an agreement with Tucson Electric Power. From there, the CAISO delivers the energy to CED at the Vista Substation.

As a result of the lawsuits filed against the plant alleging violations of the Clean Air Act, the project participants agreed to decommission Units 2 and 3 down no later than December 31, 2017 and add non selective catalytic reduction equipment to units 1 and 4.

The California owners of Unit 4 (Anaheim and Modesto Irrigation District, Santa Clara and Redding or MSR) are trading their ownership in Unit 4 for capacity in Unit 3 so that when Unit 3 is decommissioned in 2017, they will have no remaining capacity in the project.

The California participants (SCPPA, Anaheim and MSR) are currently in negotiations with the remaining plant owners over the terms of the unit decommissioning. Decommissioning involves restoring the site to its original conditions and a number of environmental mitigation efforts. There was no consideration of shutting the plant down in phases by the participants in the original agreements and no agreement on how future costs incurred by the remaining owners would be allocated to the departing owners.

Of concern to the owners remaining in the project is that there could be environmental mitigation measures required in the future that the departing owners should bear some cost responsibility. The departing owners are attempting to eliminate any future costs or liabilities. The negotiations are ongoing and likely to continue for some time into the future.

SJ3 Costs

The following table shows the annual costs and cost per MWh paid by the CED for energy from SJ3 between 2007/08 and 2011/12 and forecasted costs for FY 2012/13 through 2014/15.

	FY 2007/08	FY 2008/09	FY 2009/10	FY 2010/11	FY 2011/12	**FY 2012/13**	**FY 2013/14**	**FY 2014/15**
Total Cost (000,000's)	$14.098	$11.182	$14.577	$11.926	$12.826	$15.335	$12.192	$12.192
Generation (MWh)	192,182	211,088	189,543	209,845	240,192	193,284	220,608	220,606
Average Cost/MWh	$73.40	$53.00	$76.90	$60.00	$53.30	$79.34	$51.09	$51.09

Beginning in 2009, SJ3 costs have begun rising due to increased environmental regulations and several expensive maintenance requirements including the replacement of the boilers. The large jump in annual costs between 2011/12 and 2012/13 was due to the expected installation of SCRs necessary to comply with EPA's 2011 order to reduce NOx emissions from the plant. The decline in costs in FY 2013/14 and beyond is due to reduced maintenance of the unit in anticipation of the shut-down and a reduction in the spending for environmental mitigation.

With the anticipated retirement of the unit in 2017, O&M costs are likely to decline (possibly leading to more frequent outages) over the next few years. Partially offsetting the reduced O&M and capital expenditures will be greater debt service payments as the remaining debt will be retired three years earlier than originally planned.

One of the biggest concerns of CED is that the reduced O&M expenditures results in an unplanned permanent shut-down prior to the planned decommissioning date in 2017. This could result in CED having to purchase replacement capacity and energy in the marketplace at significant increased annual cost.

Magnolia Power Project

CED has a 4 percent entitlement (10 to 12 MW) in the Magnolia Power Project (Magnolia) located in Burbank, California. SCPPA is the owner of Magnolia, with the other project participants including Anaheim, Burbank, Cerritos, Glendale and Pasadena.

Magnolia is a 310 MW combined cycle generator. A combined-cycle generator captures exhaust heat in a heat recovery steam boiler and uses the waste heat to produce more energy. Because of the recovery of the waste heat, Magnolia has a very high efficiency and produces much less emissions than simple-cycle generators that burn gas and emit heat and emissions through the stack.

Magnolia Natural Gas Supplies

CED's gas requirements for Magnolia are around 1,600 MMBTU/day. To meet the gas requirements, CED has entered into a number of long-term gas supply contracts.

Pinedale Project

SCPPA negotiated its first purchase of existing natural gas wells in 2005. The Pinedale Natural Gas Project (Pinedale) reserves are located in west/central Wyoming.

Pinedale includes 38 operating oil and gas wells and associated lateral pipelines, equipment, permits, rights of way, and easements used in production.

In addition to Colton, that has 7 percent of the Pinedale Project, participants include Anaheim, Burbank, Glendale, Los Angeles, Pasadena, and the Turlock Irrigation District. Currently, Colton gets about 400 MMBTU/day from Pinedale.

The total cost of the Project was over $300 million. Los Angeles and Turlock hold their interests individually, while Anaheim, Burbank, Colton, Glendale and Pasadena have ownership through SCPPA.

LADWP serves as Project Manager for the overall project.

Barnett Natural Gas Reserves Project

In 2006, SCPPA members purchased natural gas reserves in Texas, northwest of Dallas. The purchased assets are located in one of the most active and largest natural gas fields in North America.

The acquisition by SCPPA and Turlock Irrigation District of the Barnett Natural Gas Reserves Project (Barnett) has approximately 37 billion cubic feet of equivalent proven reserves.

The operator of the properties is Devon Energy Corporation. Devon is the largest acreage holder and producer in the Barnett Shale, and at the time of purchase, had over 22 drilling rigs operating in the field.

Colton has a 9 percent entitlement in the project. The other SCPPA participants are Anaheim, Burbank, Pasadena, and the Turlock Irrigation District. (Turlock holds its interest individually). Currently, Colton receives about 400 MMBTU/day from the Barnett Project.

For economic, environmental, and reliability reasons, SCPPA members have invested heavily in base-load natural gas generation. This acquisition helps ensure the firm delivery of natural gas at stable prices in a highly volatile natural gas market.

Pre-Paid Natural Gas

SCPPA Bonds were issued in 2007 for the purpose of funding a lump-sum prepayment of future natural gas deliveries to the Project Participants over the next 30 years.

The total aggregate quantity of gas to be delivered by the gas supplier (J. Aron & Company) over the term of the Prepaid Natural Gas Sales Agreements is approximately 135 billion cubic feet.

SCPPA entered into separate Gas Supply Agreements with each of the Project Participants. Each gas supply contract provides for the discounted sale to Participants, on a pay-as-you-go basis, of all of the natural gas to be delivered to SCPPA over the term of the Prepaid Natural Gas Sales Agreement (Prepay Agreement). The price that the participants pay is the daily Southern California Citygate index less (approximately) $0.70/mmbtu.

The CED has an 11 percent share of the pre-paid natural gas supplies. The other SCPPA participants are Anaheim, Burbank, Glendale and Pasadena. The amount of daily gas varies by month from a high of about 55,000 MMBTU in July and August to as little as 19,700 MMBTU in the spring.

A fixed quantity of natural gas will be delivered over approximately 30 years by J. Aron & Company, with specified daily quantities of gas each month to delivery points on the natural gas pipelines that serve the Participants.

Under the structure of the Prepaid Natural Gas Project, J. Aron has also agreed to remarket, on a daily or monthly basis, quantities of gas designated by SCPPA or its agent at such times as these services may be necessary.

Summary of Gas Contracts

The following table presents a summary of Magnolia's annual costs (including natural gas and transmission costs over LADWP's system) between 2007/08 and 2011/12 and forecasted values for the following three years.

	FY 2007/08	FY 2008/09	FY 2009/10	FY 2010/11	FY 2011/12	**FY 2012/13**	**FY 2013/14**	**FY 2014/15**
Total Cost (000,000's)	$6.720	$6.295	$5.164	$4.949	$6.536	$6.137	$5.678	$6.145
Generation (MWh)	64,403	67,305	73,788	49,738	59,906	55,769	59,906	70,008
Average Cost/MWh	$107.7	$93.50	$70.00	$99.50	$109.10	$110.00	$103.50	$87.70

Palo Verde Nuclear Generating Station (PVNGS)

PVNGS is located near Phoenix, Arizona. The total capacity of the three generators is more than 4,000 MW. SCPPA owns 225 MW of capacity of which Colton has a 1.3 percent entitlement, or about 3 MW.

Power from the PVNGS is transmitted over the Mead-Phoenix/Mead-Adelanto projects and then over LADWP lines from Adelanto to SCE lines at Lugo for delivery to Colton.

Palo Verde is operated by APS and jointly owned by APS, Salt River Project, Southern California Edison Co., El Paso Electric Co., Public Service Co. of New Mexico, SCPPA and the Los Angeles Department of Water & Power.

CED has slightly less than 1 MW of capacity in each of the three units at PVNGS.

The following table shows the annual and forecasted costs of PVNGS to Colton.

	FY 2007/08	FY 2008/09	FY 2009/10	FY 2010/11	FY 2011/12	**FY 2012/13**	**FY 2013/14**	**FY 2014/15**
Total Cost (000's)	$875	$708	$706	$771	$784	$723	$745	$764
Generation (MWh)	15,577	17,955	18,948	18,627	18,609	18,000	18,000	18,000
Average	$55.10	$39.40	$40.70	$42.10	$38.80	$41.40	$42.400	$43.50

Cost/MWh									

Hoover Uprating Project

The Hoover Dam in Nevada is one of the most important power facilities for Southern California, with a total capacity of over 1,950 MW divided between Nevada, Arizona and California and over 1,000 MW delivered to southern California utilities.

In 1983, the generators at Hoover had to be replaced. SCPPA participants paid for the replacement which resulted in an additional 80 MW of generation capacity that was divided among the SCPPA participants (the Uprating Project).

The original contracts expired in 2017 but in 2012, Congress extended the SCPPA participants power purchase agreements for 50 years. In exchange for this long-term extension, Colton's entitlement of 2 MW would be reduced by about 5 percent (or 100 kW)..

Hoover is Colton's most economical resources, with energy costs of less than $32/MWh.

The following table shows Colton's historical and forecasted costs for Hoover.

	FY 2007/08	FY 2008/09	FY 2009/10	FY 2010/11	FY 2011/12	**FY 2012/13**	**FY 2013/14**	**FY 2014/15**
Total Cost (000s)	$73.2	$75.6	$75	$80.0	$80.0	$8	$82,532	$81,000
Generation (MWh)	3,420	3,352	3,056	3,388	2,617	2,617	2,807	2,807
Average Cost/MWh	$24.80	$27.1	$28.90	$27.40	$27.7	$27.3	$28.70	28.80

Agua Mansa Power Plant

The AMPP is a 43 MW (net) GE LM-6000 natural gas fired generating facility located in Colton. The AMPP became commercially operational in 2004.

AMPP was designed as a peaking facility to operate only a few hours per day, primarily during the summer on-peak periods. AMPP is too inefficient to operate as a baseload resource in comparison to other generation units in the CAISO. Instead, AMPP provides other benefits to the CED in terms of acting as a physical hedge against price spikes in the CAISO market and meeting CED's resource adequacy requirements, especially local RA capacity obligations.

The following table shows AMPP's annual costs and generation.

	FY 2007/08	FY 2008/09	FY 2009/10	FY 2010/11	FY 2011/12	FY 2012/13	FY 2013/14	FY 2014/15
Total Cost (000's)	$3,927	$3,260	$3,025	$1,449	$2,011	$5,039	$2,592	$3,000
Generation (MWh)	50,868	52,280	30,030	15,207	26,349	19,640	20,000	20,000
Average	$119.4	$87.78	$121.97	$137.91	$139.38	$76.77	$129.60	$150.00

Cost/MWh	1								

The above costs for AMPP do not include debt service costs that would add approximately $2,900,000 annually to total cost, approximately doubling the average cost per MWh.

Beginning in 2011/12, the energy from AMPP is included in the total cost of non-firm and day-ahead purchases. This will be further discussed in the power supply cost forecast section.

Renewable Resources

CED has power purchase agreements (PPAs) with three renewable projects, the Colton Landfill Gas Generator owned by Fortistar, the High Wind Project and the Metropolitan Water District (MWD). Together, these three resources produce between 20,000 and 25,000 MWh of energy annually or about 6 to 7 percent of Colton's total energy requirements.

High Wind Energy Center

The High Winds Energy Center (High Winds) is located along northern California's Montezuma Hills in Solano County, midway between the population centers of San Francisco and Sacramento. It is one of the largest wind projects in California.

In September 2003, SCPPA member cities of Anaheim, Azusa, Colton, Glendale, and Pasadena joined together in a long-term agreement to purchase wind energy through power marketer Iberdrola Renewables from the owner FPL Energy. Merced Irrigation District is also a customer at this project site.

The site has 90 Vestas V80, 1.8MW wind turbines with a total generating capacity of 162 MW. SCPPA's share is 30 MW, or 20% of the project output and CED's share is 3 percent of SCPPA's share or 1 MW.

Under this agreement, Iberdola delivers 1 MW per hour to Colton regardless of the wind production. The difference is made up of energy purchased from either the CAISO or Navajo Power Plant, a coal project in Arizona. At the end of each month, Iberdola identifies the amount of renewable energy provided. In 2012, Colton received about 7,024 MWh of renewable energy and 1,736 of non-renewable energy from the project.

The cost of energy from the High Winds Project is $53.50/MWh.

Colton Landfill

The Colton Landfill is a biogas generation facility located on the southwest portion of Colton on the site of the County landfill. A collection system collects biomethane released by the decomposition of trash buried in the landfill and then uses this biomethane as fuel for several small generators located at the site. Hourly generation can be as much as 1.2 MW but depends upon a variety of factors such as wind, temperature and moisture that affect the speed of decomposition and efficiency of collection. Average hourly generation is slightly less than 1 MW per hour

Landfill generators generally have a life of around 12 – 15 years with biomethane production beginning to decline around ten years after the landfill has been closed.

The cost of energy from the Colton Landfill is $92.50/MWh. In 2012 Colton received about 7,200 MWh from the Colton Landfill.

<u>Metropolitan Water District Small Hydroelectric Projects</u>

SCPPA purchased up to 17 MW of power, generated from four small hydroelectric generating plants located along the Metropolitan Water District (MWD) distribution system. Output is dependent on water flow from the State Water Project. Because each of the four projects is smaller than 30 MW, they qualify as renewable energy sources under RPS rules.

CED receives 22 percent of the 17 MW total, or up to 3.7 MW, of any generation as a renewable energy supply. CED separates the energy into two components, brown energy and the green renewable capacity components. CED then sells the energy to the City of Anaheim and the hourly index price for the CAISO and keeps the green renewable energy capacity component for RPS compliance.

The net result of the sale of the MWD energy is that CED keeps the renewable energy credit at a cost equal to the difference between $95/MWh (the purchase price from MWD) and the CAISO index price. For the past year, this spread has been around $45- 50/MWh. However, CED does not receive any energy from the MWD projects.

On an annual basis, CED has been receiving about 10,000 MWh of renewable energy from the purchase.

Short-Term MWD Purchase

In November and December 2013 CED has purchased up to 12,000 MWh of renewable energy from MWD at the energy index price plus $30 per MWh. This energy is not necessary to meet load requirements but helps increase CED's renewable purchases, increasing CED's green energy percentage to almost 11% in 2013. The total cost of the purchase is between $600,000 and $660,000, depending upon actual power generation from the MWD facilities.

CED is still exploring the possibility of purchasing another 12,000 MWh in short-term purchases from MWD or another renewable generator to increase its renewable portfolio percentage to around 16% of total retail sales.

<u>Summary of Renewable Resources</u>

CED currently has about 26,000 MWh annually of renewable energy or almost 6 percent of total sales. Under SB 2, CED is required to purchase or generate about 70,000 MWh annually during the period 2011-2013. A small portion of the shortfall can be satisfied by the purchase of Renewable Energy Credits

(RECs) in the marketplace but CED will still be short some 40,000 – 45,000 MWh of renewable energy in 2013.

CED is also purchasing another 20,000 MWh from MWD in November and December 2013 under a short-term contract in order to increase its renewable energy purchases and is exploring other possible purchases. CED anticipates that between 12 and 15% of its retail sales will be met by renewable resources in 2013.

Transmission

The CAISO has assumed operational control of all 115 kV and above transmission of all Participating Transmission Owner (PTO) utilities and transmission owners such as Citizens Energy that have turned their operational rights over to the CAISO and the 115 kV and 69 KV transmission of PG&E and SDG&E. The CAISO operates all this transmission to minimize daily transmission costs for the system as a whole.

Each PTO utility charges the CAISO the total cost of its transmission plus a rate of return on any owned transmission assets. The charge is called a utilities transmission revenue requirement (TRR). The CAISO aggregates the TRRs of all PTOs and then divides this amount by the forecasted energy use on its system for the year in order to develop a transmission wheeling rate that is paid based upon the total metered load of the LSE. This rate is a "postage stamp" rate paid by the entity that takes final delivery of the energy. It is called a postage stamp rate because every entity pays the same amount regardless of the voltage) or how far energy is wheeled across the system.

Any generator or load can use the CAISO system. To manage the use of the transmission system, the CAISO uses congestion pricing. In effect, if entities schedule more energy over a transmission path than the path's capacity, the CAISO begins adding a congestion charge to encourage entities to either move energy to other transmission paths or to back generation down over that path. The CAISO keeps increasing the congestion charge until generation is reduced to the transmission limits over a specific path[10].

Congestion charges can be quite high over some constrained paths, often more than the price of energy being transmitted over these lines.

The congestion charge is a tradable commodity with entities being allowed to purchase and trade the rights to receive congestion charges over a specific transmission line segment. These rights to receive congestion charges are known as congestion revenue rights (CRRs).

There are two ways LSE's acquire congestion rights, through a CAISO allocation process and an auction process.

Load serving entities that use a specific transmission path are eligible to receive an allocation of free CRRs tied to the length of their ownership or power sales purchases from specific generators. Generally,

[10] This is actually done by a mathematical formula approach that creates a large enough congestion charge to push higher priced resources out of the dispatch order.

only about two-thirds of the capacity in a generator is allocated CRRs with the utility (or LSE) subject to congestion charges for the remaining capacity. If the LSE wants to protect itself against congestion charges for all its generation, it will have to participate in the CRR monthly allocation process and CRR auctions and bid against other entities for the right to recover any potential congestion charges.

The CAISO allocates its transmission capacity to LSE's based upon existing unit specific generation contracts. If an LSE has a power purchase agreement (PPA) or generator entitlement, it can request CRRs from the CAISO through an annual or monthly allocation process. Because the revenues that the CAISO receives in congestion charges should approximately equal payments to CRR owners, the CAISO is indifferent to congestion revenues paid on a specific line so long as it does not allocate more transmission capacity than available on a specific path.

Entities requesting CRRs on a specific path will only receive their full request if the path has excess capacity after all existing CRR holders and LSE's without rights on a particular path have applied to the CAISO for transmission right during the annual allocation process. If the CAISO has already allocated all the CRRs on a path, the requesting entity may not receive any CRRs or only a portion of their request.

If an entity does not receive an allocation of CRRs, it can enter the CRR auction process. In the auction process, any (creditworthy) entity can offer to "sell" CRR revenues for a price determined in a weekly auction along a specific transmission path. If an entity sells CRRs, it is responsible for paying the CRR costs to the purchasing entity.

The risk of a CRR is that if a LSE has CRRs over a particular path and the congestion changes to the opposite direction, the owner of the CRRs has to pay congestion costs. That is, acquiring CRRs is not a risk free proposition. Generally however, congestion flows are fairly predictable with congestion costs high coming into the LA basin and very low for entities exporting from the basin.

Even though CED has some transmission rights, it turned these rights over to the CAISO when it became a PTO. In exchange, it received some CRRs on the transmission paths. But the CRRs are not sufficient to completely protect CED from incurring transmission congestion costs.

CED has the following long-term transmission contracts:

Mead-Adelanto Project

The Mead-Adelanto Transmission Project is comprised of a 500 kV alternating current transmission line extending between the Marketplace Substation in southern Nevada and Adelanto Switching Stations near Victorville.

The City of Colton is entitled to firm bidirectional service equaling 1.75% of the facility's 1,291 MW rated capability, or 22.59 MW.

Mead-Phoenix Project

The Mead-Phoenix Transmission Project is a 500 kV alternating current transmission line a 500 kV alternating current transmission line extending between Westwing and Perkins Substation. CED is entitled to firm bidirectional service equaling 0.2308% of the facility's 1,923 MW rated capability, or 4 MW.

CED also has an entitlement in the 500 kV alternating current transmission line extending between Perkins and Mead Substations. With regard to this component, the City of Colton is entitled to firm bidirectional service equaling 0.2308% of the facility's 1,923 MW rated capability, or 4 MW.

The Mead-Phoenix Transmission Project includes a segment of Marketplace-McCullough transmission line, a 500 kV alternating current transmission line extending between the Marketplace and McCullough Switching Stations.

As part of both the Mead-Adelanto and Mead-Phoenix Transmission Projects, CED is entitled to firm bidirectional service equal to its transmission entitlements in Mead-Phoenix and Mead- Adelanto between McCullough and Marketplace (4 MW in Mead-Phoenix and 22.59 MW in Mead-Adelanto).

Adelanto-Victorville/Lugo

The Adelanto-Victorville/Lugo path is comprised of 500 kV alternating current transmission facilities extending between the Adelanto Switching Station, the Victorville Switching Station, and the midpoint of the Lugo-Victorville 500 kV line.

CED is entitled to firm bidirectional service over this path in an amount up to its transmission service entitlement in the Mead-Adelanto Project (i.e., 22.59 MW).

Lugo/Victorville 500 kV to Vista 230 kV

CED's 21 MW entitlement to firm unidirectional network service from the midpoint of the Lugo/Victorville 500 kV line to the Vista Substation 230 kV Substation is derived from two separate agreements with the Southern California Edison Company (SCE):

- One agreement providing for 3 MW of service.
- One agreement providing for 18 MW of service.

Mead 230 kV to Vista 230 kV

Colton's 3 MW entitlement to firm unidirectional network service from the Mead Substation 230 kV bus to the Vista Substation 230 kV bus is derived from a firm transmission service agreement with SCE.

Devers Substation to Vista 230 kV

CED's 14.043 MW entitlement to firm unidirectional network service from the Devers Substation to the Vista Substation 230 kV bus is derived from a firm transmission service agreement with SCE. CED does not use this path for any specific resource.

Summary of CED's Generation and Transmission Portfolio

CED did not have any transmission entitlements from Palo Verde Substation, the delivery point for energy from San Juan, to Colton. As a result, CED was paying significant congestion costs to transmit the San Juan generation to Colton. By becoming a PTO, CED was allocated about 20 MW of spring and summer CRRs and a small amount of winter and fall CRRs. But CED has to participate in the monthly CRR allocations and auctions to acquire more CRRs and protect it against congestion costs.

CED can sign power supply contracts with any generator interconnected on the CAISO grid. While the transmission costs is fixed (at least annually) congestion costs change from hour to hour depending upon CAISO loads, the location of generators and whether or not specific transmission paths have been derated for maintenance.

CED does have some CRRs to protect against congestion costs from the Phoenix area to Colton, but not enough to avoid monthly congestion payments during the winter and fall.

As a PTO, CED has been able to reduce its annual transmission costs but CED has more exposure to congestion and must manage daily congestion costs more carefully than it has in the past. The majority of CED's congestion risk will remain between Palo Verde and Colton where most of CED's energy resources are located..

Chapter 4
Legislative and Regulatory Issues

Introduction

The past seven years have seen legislative and regulatory bodies impose numerous environmental and operating requirements on electric utilities. While the new legislation will reduce Greenhouse Gas (GHG) emissions and result in less pollution, the legislation will also cause increased operating costs in the near term while possibly reducing costs in the future. The legislative and regulatory activities have also significantly changed the way utilities plan for and acquire new transmission and generation resources. No longer do utilities plan to acquire resources based solely on least-cost planning considerations. Utilities also have to explicitly address regulatory issues that limit their ability to acquire renewable energy supplies from economic resources due to geographical limitations on the location of these resources and transmission congestion issues.

The major legislative and regulatory initiatives facing the CED today include:

- GHG reduction, including the Federal Clean Air Act and California's AB 32 Greenhouse Gas Reduction Law and Renewable Portfolio Standards requirements;
- Changes in the California wholesale electricity market including the proposed flexible capacity mechanism;
- Changes in the CAISO resource procurement and scheduling process;

Implementing many of the requirements is difficult due to over-lapping regulatory bodies that may or may not have jurisdiction on some issues. For example, until 2011, California required both the Public Utilities Commission (CPUC) and California Energy Commission (CEC) to regulate RPS compliance. However, the CPUC did not have jurisdiction over publically-owned utilities and the CEC does not (generally) have the ability to enforce their decisions. In many situations, local regulatory bodies, such as the Colton City Council, were able to declare themselves in compliance with state renewable energy requirements. As a result, both federal and state legislatures have resorted to putting the enforcement of new rules under environmental bodies such as the federal Environmental Protection Agency (EPA) and the California Air Resource Board (CARB) that have jurisdiction over local utilities regardless of conflicting regulatory overlaps.

Federal Clean Air Act

The greatest immediate financial impact on CED is due to more rigorous enforcement of the Federal Clean Air Act at SJ3. SJ3 was one of the largest emitters of nitrogen oxides in the west but between 2006 and 2010 installed new environmental controls that reduced daily emissions by up to 80 percent and significantly reduced mercury and carbon dioxide emissions. The cost of this environmental upgrade was $320 million and CED's share was approximately $5.45 million.

Even with the environmental upgrade completed, EPA was required to open another investigation on regional haze caused by San Juan as the result of a lawsuit filed by the Sierra Club and Natural Resources Defense Council (NRDC). At the conclusion of the investigation, EPA ordered the San Juan owners to install Selective Catalytic Reduction (SCR) equipment on the plants at a cost of between $750 million and $1.0 billion and have the upgrades completed by 2017.

CED's cost-share of these cost upgrades would have been between $18 – 23 million, with the cost impacts beginning in 2013.

The San Juan participants appealed EPA's initial decision and requested that they be allowed to install non-selective catalytic reduction (NSCR) equipment that would reduce emissions by 80 to 90 percent of the SCR levels but at only around 10 percent of the total cost.

In 2011, EPA rejected the San Juan owner's proposal and reaffirmed their initial decision on the need to install SCRs but gave the owners of San Juan five years to complete the work rather than three as initially ordered. However, this did not change the schedule for SCPPA participants.

PNM also filed suit against the EPA requesting a stay of EPA's order. In March, 2012 the 10th Circuit Court of Appeals rejected PNM's request for stay and ordered work to proceed on the environmental upgrades.

In March 2012 the New Mexico Public Service Commission (NMPSC), ordered an inquiry into alternatives for San Juan. Options studied included conversion of the plant to a renewable site and natural gas generation rather than coal generation.

PNM continued negotiations with EPA on alternatives to the installation of SCRs at the plant and with the other San Juan owners. In February 2013, PNM and EPA agreed to decommission Units 1 and 3 no later than December 31, 2017 and install NSCR equipment on the remaining 2 units. The California owners (including CED) will not have any rights to capacity or energy from the SJGS once SJ3 is decommissioned.

The negotiations currently ongoing between the participants deal with how to implement the settlement and cost shares. The participants remaining in SJGS will reduce their costs significantly, perhaps by as much as $650 million, by decommissioning the two units and installing NSCR equipment compared to SCRs. At the same time, these same participants argue that their future costs could rise due to as yet unknown additional environmental costs necessary to restore the site in the 2050 time period. The California owners, who are abandoning the SJGS, are unwilling to assume all potential future environmental costs.

The major concerns of the ongoing negotiations include costs of common facilities (facilities that were built to support all 4 units at the SJGS, not just specific units), coal mine decommissioning and plant decommissioning when the remaining 2 units are shut down in the 2050 time frame (maybe earlier or later depending upon future costs and environmental laws). There are also some less important issues, such as the value of the existing coal inventories that have to be addressed in the near term.

Obama Administration Climate Change Initiative

In July, 2013 the Obama Administration announced plans to reduce CO2e as part of a broad attack on climate change. Although the details of the Administration's carbon reduction goals have not yet been released, the Administration intends to use its regulatory (as opposed to legislative) powers to require power plants to reduce carbon emissions.

The primary focus of the Administration's initiative appears to be reducing coal-fired generation. The Administration apparently would like to see more coal plants replaced with natural gas fired generation and renewable energy projects.

At this time, the scope and possible regulations resulting from the initiative are unknown. However, it is possible that energy prices could rise in the future as utilities enter a period of capital expenditures to meet the CO2e goals.

<u>State Clean Air Legislation</u>

The umbrella legislation for California's clean air legislation is AB 32. This legislation establishes the goal of reducing emissions by California's residents and businesses from current levels back to 1990 levels. AB 32 established the C&T approach to pollution control and indirectly required renewable energy portfolios. AB 32 has spawned significant follow-up legislation and regulatory activity to determine how to meet the goals established in the law.

With the passage of AB 32 in 2006, California is leading the nation in addressing climate change, with an overall goal of reducing statewide GHG emissions to 1990 levels by 2020 and setting a path to further reductions by 2050. There have been several attempts at the federal level to address climate change, both through legislation and EPA regulations. With the exception of GHG reporting requirements for major sources (25,000 metric tons), federal actions have stalled. Nonetheless, California continues to push to reach its overall GHG emissions reductions goal.

In 2008 the California Air Resources Board (CARB) adopted the Climate Change Scoping Plan, which identifies measures for the various economic sectors that would achieve real GHG reductions. Several measures have been identified for the energy sector that have been or will be developed into regulations. The following apply to CED:

- AB 32 Cost of Implementation Fee Regulation (Fee Regulation)
- Regulation for the Mandatory Reporting of GHG Emissions (Mandatory Reporting Regulation)

- Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear (SF_6 Regulation)

The 2010 Mandatory Reporting Regulation revisions increased the exemption threshold for reporting for electric generating facilities from 2,500 metric tons (MT) to 10,000 MT, and reduced retail seller reporting obligations as well as verification requirements starting in 2012

A key portion of AB 32 is the requirement for increased energy efficiency measures and advanced lighting technologies. AB 32 requires that utilities implement all cost-effective energy efficiency measures prior to acquiring new generation resources.[11]

Cap and Trade

The most immediate issue facing CED in 2013 will be implementing the C&T regulations that went into effect in July 2012.

Under the C&T program, the total amount of emissions in tons per year (measured in CO2e or carbon dioxide equivalents) is capped by CARB. CARB has estimated emissions by industrial sector by performing audits of emissions by sector for the past three years with each business or entity covered by the regulation required to estimate its annual emissions and then have its emissions verified by an independent auditor approved by CARB.

CARB then allocated each entity within each covered industrial sector emission allowances (EA). If the entity accurately reported its emissions, the allocated EAs would equal the average of the annual emissions over the past three years.

Each year CARB performs an audit of the emissions from each entity. If an entity does not have sufficient EAs to offset all its emissions, it must either purchase EAs from another entity or pay a fine of about $50/ton for emissions above its EAs. If an entity has more EAs than emissions, it will retire the EAs necessary to offset its emissions and can then sell any remaining EAs. There is no expiration on EAs so purchasing a 2013 EA allows an entity to use that EA any time after 2013 but future EAs cannot be brought back to meet past compliance obligations. So a 2013 EA can be used to meet 2015 requirements but a 2017 EA cannot be used until 2017 or later.

Each year, the amount of EAs available and allocated to each entity declines, forcing all entities to reduce their emissions by about 1 percent per year in aggregate.

CED has been allocated 234,600 EAs for 2013. CED has reported its 2012 electricity sales and imports of energy from out-of-state sources which were used to estimate annual emissions..

[11] Refer to Chapter 4 of the IRP for information about CED's current and planned energy efficiency programs.

The freely allocated EAs can only be used to offset emissions associated with retail sales. CED cannot use any of its freely allocated allowances to offset emissions from surplus generation or generation sold into the CAISO market. As a result, CED must track all its hourly generation and emissions, determine which energy is used to meet retail load and which energy is surplus to load and then acquire EAs to offset emissions associated with surplus sales.

Initial estimates suggest that CED's emissions are between 255,000 tons per year and 265,000 tons per year. If actual emissions to serve load are less than 234,600, then CED can sell excess EAs and use the revenues for reducing power supply costs by investing in renewable alternatives. If actual emissions are greater than 234,600 tons, then CED will have to purchase EAs.

CED personnel have been trained to participate in the auction process (and will participate in the August 2012 EA auction). CED is still developing procedures for calculating emissions, tracking CED's emissions relative to its freely allocated EAs and buying or selling EAs as necessary to remain compliant with the C&T program. CED will also have to develop financial tools to track the revenues and costs from C&T programs and restrict how these funds can be used.

One of CED's greatest problems with implementing its internal C&T compliance program is that the final rules have not yet been adopted. Of immediate concern is the way that freely allocated EAs can be used to offset emissions. This issue is called the stacking order problem.

The stacking order is the way resources are dispatched to meet load. For example, suppose a utility has two 20 MW resources, a clean resource with little or no emissions and a dirty resource with high emissions and a load of 30 MW. From the utility's viewpoint, it would like to "stack" its resources with the dirty resource on the bottom (so as not to create any surplus energy) and its clean energy on top (that results in 10 MW of surplus energy).

The utility would like to use its freely allocated allowances to offset the full 20 MW of its dirty resource and not have to purchase any additional EAs in the market. However, if the clean resource has to be stacked first, then the "dirty" resource creates surplus energy that the utility cannot use its freely allocated EAs to offset. The utility would have to buy the equivalent CO2e of 10 MW at a current price of around $15.00 or a total amount of $150 for the 10 MW surplus for one hour.

CED has additional issues dealing with AMPP. AMPP is dispatched by the CAISO and dispatch generally results in surplus energy. The CAISO adds a payment for the cost of EAs but given the price varies on a day to day basis (although the variation is currently small) CED has to ensure that it acquires EAs in the market at a price less than or equal to what the CAISO paid or risk losing money on a AMPP dispatch.

CED personnel are working with other utilities and CARB to resolve the stacking issue along with other open issues that impact how the C&T program works.

Renewables Portfolio Standard (RPS) Legislation

The second major component of AB 32 was the requirement of a renewable portfolio standard for all LSEs within California. Governor Schwarzenegger has initially used AB 32 in establishing minimum renewable energy requirements for investor-owned utilities. However, there was a debate on whether or not his Executive Order should be applied to publically-owned utilities.

In April 12, 2011, Governor Brown signed SB 2, codifying into law an increase of the RPS mandate to 33 percent by 2020. SB 2 made significant modifications to the RPS program, including the use of multi-year compliance periods with incremental targets and the specification of minimum product content for most retail sellers' RPS portfolios that changes with each compliance period. SB 2 also modified certain delivery requirements for out-of-state resources and limited the ability to carry forward unbundled renewable energy.

A key component of RPS is the concept of a Renewable Energy Credit or REC. For purposes of regulatory compliance, energy is classified as "renewable" or non-renewable." Non-renewable energy is from traditional fossil-fuel generation. Renewable energy is from renewable energy sources. Renewable energy can be further divided into two components, the energy and the renewable capacity attribute. A renewable energy generator can separate the brown energy component from the renewable energy attributes and sell the renewable energy as a REC.

For example, a wind generator in California can generate energy and sell it into the CAISO market as non-renewable energy and retain the REC. The REC can then be sold to an entity that wants to offset its brown energy purchases and turn them into green energy. However the use of RECs by utilities is limited by SB 2.

Compliance Categories of RPS Resources

SB 2 established three Power Content Categories (PCC), or "buckets," for RPS compliant resources. PCC 1 is bundled green energy produced within California or that has its first point of interconnection with the CAISO controlled grid. PCC 3 is RECs.

PCC 2 is firmed and shaped green energy, or energy from renewable sources that does not meet the criteria of categories 1 or 2.

Resources must meet the following criteria during the different compliance periods.

Categories (Buckets)	Description	Percentage of RPS Target
1	A. Energy from eligible resources that have the first point of interconnection with a California Balancing authority or with distribution facilities used to serve end users within a Califonria balancing authority, or; B. Are schedule into a California Balancing auhority without substituting elelctricity from another source. If another source provides real-time ancillary services to maintain an hourly import schedule. If another source provides real-time ancillary services to maintain an hourly import schedule into California, only the fraction of the schedule actually generated by the renewable resources will count, or; C. Have an agreement to dynamically transfer electricity to a California balancing	Period 1: Minimum of 50% of the energy that is counted towards RPS target Period 2: Minimum of 65 percent Period 3: Minimum of 75%
2	Firmed and shaped energy or RECs from eligible resources providing incremental electricity and scheduled into a California balancing authority	Period 1: Maximum of 50% Period 2: Maximum of 35% Period 3: Maximum of 25%
3	Energy or RECs from resources that do not meet the requirements of categories 1 or 2, including unbundled RECs	Period 1: Maximum of 25% Period 2: Maximum of 15% Period 3: Maximum of 10%

The final rules for RPS compliance were adopted by the CEC in May, 2013. Now the utilities are attempting to understand what their obligations in terms of reporting requirements and regulatory compliance.

One of CED's concerns is the rules governing the use of biogas. Because of its ownership of two gas-fired generators, CED would like to be able to use biogas as a means of meeting its RPS requirements.

In March, 2012 the CEC issued a Notice to Consider Suspension of the RPS Eligibility Guidelines for Biomethane. In this Notice, the CEC stated that it did not believe that biogas injected into the interstate pipeline system qualified as a renewable resource. Onsite uses of biogas, such as a landfill gas, would still qualify.

In the Renewable Portfolio Standard Eligibility, 7th edition (RPS Guidebook), the CEC permitted the use of biomethane provided it was produced from in-state resources and either cleaned to pipeline quality or used for generation purposes on-site. In addition, any generator using biogas would have to be re-certified by the CEC.

The RPS Guidebook edition is the overall regulatory guide for RPS compliance.

While the RPS Guidebook allows the use of biogas, the restrictions on out-of-state sources and tracking criteria is likely to make future biogas sources more expensive than in the past and severely limit the amount of new biogas sources.

Summary of GHG and RPS Legislation

CED has now instituted a training program for complying with C&T. CED personnel are attending C&T training programs held by SCPPA and CARB.

CED is not in compliance with the RPS standards. CED only has about 6 percent renewable resources as opposed to the statutory requirement of 20 percent. For 2013, CED can purchase short-term energy to bring its renewable portfolio up to 8 or 9% but it will still be short about 28,000 MWh on average per year for 2011, 2012 and 2013 If CED's planned solar PV resources come on-line in 2014 (further discussed below), CED's renewable percent climbs to almost 12.5 percent. However, this will still be below the statutory requirement of 25 percent for the second compliance period.

A discussion of how CED intends to meet its RPS requirements is given in Chapter 6.

North American Electricity Reliability Corporation (NERC) Standards

In August, 2012 CED was audited for compliance with applicable NERC reliability standards. This was the first time CED is audited and required significant preparation to insure CED met its reliability standards.

NERC was established in 1968 to coordinate electricity operations of the bulk power system following the great Electricity Blackout of 1965. NERC established nine reliability coordinating regions, separated electrically from each other. The largest reliability region is the Western Electric Coordinating Corporation (WECC) that includes 9 western states and parts of western Canada and Baja Mexico.

WECC has regulatory jurisdiction over CED.

In 2007, NERC was given the authority to establish and enforce reliability standards. Most reliability standards are simple prudent utility operating requirements. However, NERC requires documentation that utilities are actually following these standards. No longer can a utility just state that it is in compliance, it must document compliance and prove that its documentation is accurate through a relatively rigorous process.

There are different reliability standards for entities based upon their ability to affect the bulk power system. Independent system operators have the most elaborate requirements, with balancing authorities having the next most elaborate set, followed by bulk transmission owners and generators and then distribution providers.

CED is currently classified as a resource planner but may be upgraded to a generation owner in the next year due to its ownership and control of the AMPP. This would add to CED's annual compliance reporting obligations.

CED's obligations under currently applicable requirements are to prepare an annual forecast of demand and energy requirements, provide 66 kV planning and operating information to the local transmission provider (SCE) and provide information on relay settings to SCE.

The information required to meet the reliability standards is not difficult. However, CED has never documented why it established current relay settings or other information about its system. The documentation process is fairly stringent, requiring copies of all correspondence and emails between CED and SCE or the CAISO.

CED is currently NERC compliant. To remain compliant will require establishing a process where all standards pertaining to CED are identified and updated whenever communication between CED and SCE occur.

Beginning in 2009, NERC expanded its compliance requirements to include cyber-security. At this time, CED is probably in compliance with the new cyber-security regulations. Generally, the cyber security regulations require isolating system control equipment from the internet, restricting access to areas where system control and data acquisition (SCADA) computer equipment is located and other minor actions necessary to limit access to control equipment away from unauthorized individuals. CED has isolated its control systems from the internet but still needs to more strictly restrict physical access to the SCADA system.

While it likely has little or no impact on CED directly, in July 2013 FERC approved WECC splitting into two different corporations. WECC itself will remain a reliability organization but the regulatory compliance will be separated from the rest of the organization if for no other reason than to ensure that the reliability portion of WECC is in compliance with NERC standards.

<u>Market Redesign and Technology Update</u>

The CAISO's Market Redesign and Technology Upgrade (MRTU) has been in operation since April 1, 2009 and, overall, the wholesale market has performed as intended. The MRTU represents a complete overhaul of California's system of wholesale power delivery as a result of the California energy crisis in 2001. While some extreme prices have occurred in the real-time market, they have been infrequent and typically reflected actual system constraints. Concurrent with the first two years of operation, the market has experienced reduced demand influenced by the economic downturn across the state, as well as increased renewable production, high hydro generation, and high volumes of self-scheduled energy.

There are two primary components to the MRTU market. First, the CAISO provides all ancillary services to California participants. Ancillary services include those services necessary to meet moment-to-moment changes in energy demand. This includes such things are regulation, local voltage support, spinning reserves and stand-by reserves. Secondly, the CAISO provides all energy supplies to all LSE's within its balancing area.

The MRTU market is actually three separate markets. First, to ensure there is sufficient capacity to meet the peak demand of all retail load in the CAISO, each LSE must have capacity resources equal to at least 115% of monthly forecasted peak demand. This capacity does not have to be from efficient resources but it must be available to the CAISO for possible dispatch each month.

The second market is the ancillary services market. The third market is the energy market.

Ancillary Services

Energy demand is not constant. Demand varies second by second as retail customers turn equipment on and off in different parts of the state. On a real time basis, California's energy demand can vary by several hundred MW from moment to moment. This moment to moment variation is met by generators that can increase or decrease generation on a real-time basis. Ancillary services refer to the different ways generation capacity can be increased or decreased to match real-time supply and demand of electricity.

In addition to load-following (or automatic generation control or AGC) there are other types of reserves ready to meet load if actual demand is different than forecasted demand.

Spinning reserves are generators that are on and available to meet load within 10 minutes. AMPP actually can meet the spinning reserve requirements of the CAISO and is eligible to bid into the CAISO ancillary services market.

Non-spinning reserves are generators that can go from a cold shut-down state to generation within one hour.

Generally, spin and non-spinning reserves are equal to 15% of load.

All these different generators have a spatial component. A generator in Sacramento cannot meet increased electricity demands in San Bernardino County, so spinning and non-spinning generation is located throughout the state.

In addition, a region using more energy than it has coming into the area needs to have additional generation (or transmission capacity) to increase generation and voltage in an area.

During the day, AGC meets the moment to moment changes in demand. As load increases, spinning reserve units are committed to meet load and more non-spinning reserves are brought online. As load begins to decline in the evening, resources are backed down in reverse order or the last resource that came online is the first to be backed down.

Energy Markets

The final CAISO market is the energy market. The MRTU market is a "closed" market where all LSE's bid their generation resources to the CAISO that then decides which resources should be used to meet load, based upon price, operating characteristics such as ramp ramps or must-run restrictions, location, transmission constraints and emissions. The CASIO also acquires all ancillary services necessary to meet the moment to moment fluctuations in demand.

No entity's generation costs should increase due to participating in the CAISO. Efficient resources are dispatched to meet loads while less efficient resources that are available to run are not dispatched but recover costs in capacity payments for being able to meet unanticipated loads or system contingencies.

If a unit (like AMPP) is not dispatched to meet CED's loads, it is because the CAISO has less expensive energy available and it sells this energy to CED in place of AMPP generation. But if prices rise above the AMPP generation cost, AMPP would be dispatched and CED would pay the incremental cost of AMPP for load purposes but receive the wholesale price for any remaining generation that is then sold in the CAISO market.

The primary difficulty with the CAISO market is the complexity of the market. CED does not currently have people with necessary skills to bid the resources into the CAISO system and so relies on Shell. CED has only recently developed the internal expertise to verify where CED acquired its daily energy, whether from CED resources or from the market, and how much CED paid for energy, ancillary services and transmission congestion.

Resource Adequacy Program

Another key aspect of the market design that will undergo enhancements is California's resource adequacy (RA) program. CED (along with all other LSE's) provides data to the Energy Commission that provides a monthly forecast of RA obligations. The forecast is equal to CED's coincident load with the CAISO plus the reserve margin of 15 percent[12].

CED currently has sufficient RA capacity to meet its requirements in the CAISO market from its own resources, other than for a few summer months in 2013, and does not have to purchase additional RA capacity.

Currently, utilities contract to meet their capacity obligations through private bilaterally-negotiated contracts or from their own resources. In June 2010, the CPUC issued Decision 10-06-018 indicating that it would not move towards a centralized capacity market or a multi-year forward resource adequacy requirement. The CPUC concluded that the existing RA contracting mechanisms and practices are sufficient and that the proposals may pose challenges for non-utility load serving entities. In 2012 the CAISO began studying various capacity market alternatives partially as the result of more renewable resources coming online.

In February 2013 the CAISO and CPUC issued a "Briefing Paper – A Review of Current Issues with Resource Adequacy" where the CPUC proposed a number of new market markets including flexible capacity markets. The problem was that the CPUC admitted that it did not know how to define flexible capacity markets. The CPUC simply addressed the fact that their was concern over the capacity markets due to the retirement of a large amount of traditional generation (such as SONGS and a number of thermal units using once-through cooling) and the amount of new renewable resources coming online that did not have the same reliability as thermal resources.

Renewable resources such as PV and wind have a reliability problem. An unexpected storm moving into an area could shut down thousands of MWs of solar PV generation. Wind is an "as-available" resource. When the wind blows the resource generates. No wind, no generation.

[12] The CAISO is studying requiring utilities to have capacity to meet their non-coincidental load

If entities have to start procuring traditional generation capacity to back up renewable resources, costs would increase significantly.

The CAISO is also proposing new, and longer, capacity procurement contracts to provide an incentive for retiring generation units to remain online simply for the RA payments.

The CAISO has already started making LSE's acquire replacement capacity in the event a RA resource is anticipated out of service for more than 10 days during the month. Utilities anticipate even more restrictions on what constitutes RA capacity will be required in the future as the proceedings move forward to new regulations.

A final concern with the proposed flexible capacity market is that LSE's will have to procure RA capacity 3 years in advance of need so that new generation can be constructed if required. This is a difficult requirement for CED to meet.

Local RA Capacity

Under MRTU, the CAISO may procure Local RA Capacity (LRAC) if the CAISO determines there is a capacity deficiency within a Local Capacity Area (LCA). A deficiency in LRAC can occur because individual LSEs do not demonstrate sufficient LRAC in annual or monthly resource plans or because of a collective deficiency of local capacity in a LCA. It should be noted that, according to the CAISO, the AMPP is counted as a Local Capacity Resource. When needed, the CAISO will make supplemental procurement for RA under the CPM provisions of its tariff. As detailed in the CAISO Tariff,[13] the CPM costs associated with the procurement of LRAC will be allocated proportionately to all deficient LSEs within each Transmission Access Charge (TAC) Area, or in the case of a collective deficiency of local capacity, to all Scheduling Coordinators that serve load in the TAC Area.

AMPP provides all of the CED's local RA capacity.

Summary of CAISO Market Modifications

In general, CED has sufficient resources to meet its capacity obligations and satisfy its energy requirements through 2017. CED relies upon the CAISO for all ancillary services and some transmission. Shell Energy is scheduling CED's resources as CED's SC. Meetings between Shell and CED identified a number of issues that are increasing costs to CED, primarily dealing with the dispatch of SJ3 and Magnolia.

[13] CAISO Tariff Section 43, Capacity Procurement Mechanism.

Chapter 5
Conservation and Demand-Side Management

Introduction

Conservation and demand-side management (DSM) programs attempt to change how much, and when, residents and businesses use energy in order to reduce their costs without changing the way they live or do business. In effect, conservation and DSM programs attempt to encourage people to become more efficient, reducing energy costs in the process.

Because of the relatively small cost of electricity to most residential customers, it is difficult to provide incentives to encourage them to make significant capital improvements for energy savings. However, commercial and industrial customers can make significant capital improvements to reduce energy use or change production hours to reduce costs.

CED's conservation and DSM programs are funded by a $0.0029/kWh public benefit charge that raises almost $1,000,000 annually for public benefit programs. The public benefit programs include conservation, DSM, low income and renewable energy programs.

Conservation Programs

Conservation refers to programs designed to reduce total energy use, regardless of when energy is used. In effect, conservation programs help people reduce a customer's energy use, without impacting their lifestyle, by using more energy efficient appliances and equipment. Examples of conservation programs offered by CED include energy efficient lighting, refrigerator replacement and energy audits.

By offering rebates, providing energy efficient equipment at no or little cost, and by educating people and businesses on how to reduce their energy costs, CED avoids having to purchase additional energy in the market and helps reduce the overall costs for all Colton ratepayers.

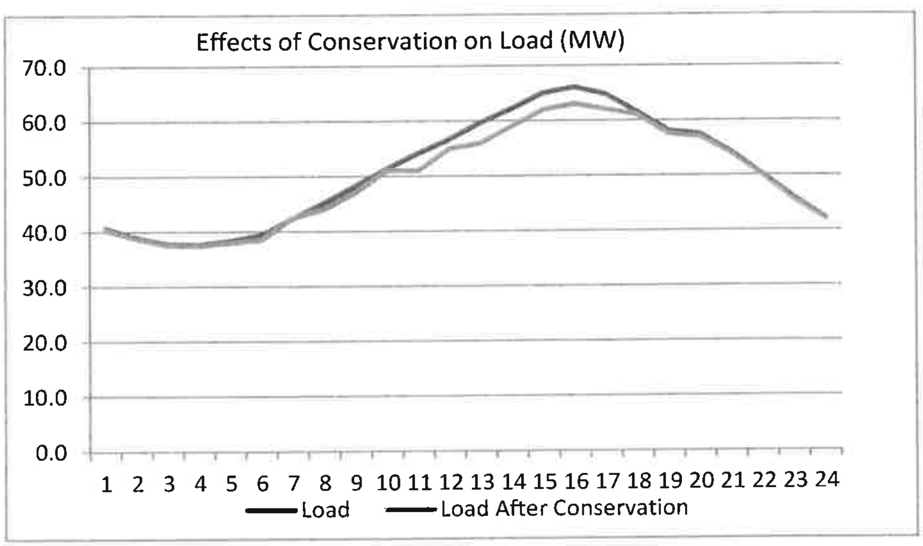


Figure 5.1: Effects of Conservation Programs on Load

DSM Programs

DSM programs differ from conservation programs in that the program goal is not necessarily to reduce energy use but instead change the timing of use. While almost all conservation programs are DSM programs, not all DSM programs are conservation programs.

Energy costs vary hourly each day, with energy use during the on-peak or high use periods much more expensive than energy use during the off-peak or low-load hours. During summer high-use periods, energy may cost two or three times more than the cost during the off-peak or low-load periods. By providing incentives, such as offering time-of-use pricing or equipment that shifts energy use to off-peak periods, CED can smooth its daily load curve and lower the cost of acquiring energy for all its customers.

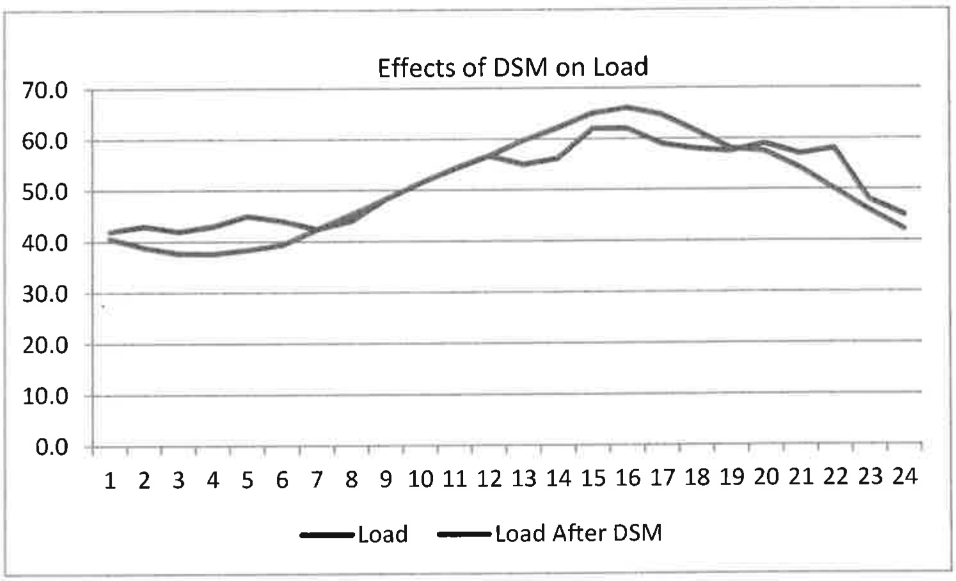


Figure 5.2: Effects of DSM Programs on Load

Evaluating Conservation and DSM Programs

There are three general ways to evaluate conservation and DSM programs; by their impact on the customer, the utility, and on society.

A refrigeration replacement program reduces the amount of energy used by a customer, but it also reduces the revenues received by the utility. Participating customers will see their energy costs decline, but non-participating customers have to cover the loss of revenue. From the participating customer's viewpoint, the refrigeration program is a good program that reduced their individual costs.

From the utility's viewpoint, the refrigeration program reduced both costs (by reducing the amount of energy that it had to purchase) and revenues (by the value of reduced sales to the customer). Depending upon the utility's cost of acquiring capacity and energy, the program may result in lower revenues but not lower costs, or costs may decline slightly, but not as much as the revenue loss.

The final way to evaluate conservation programs is to include the impacts on society of conservation programs, including the negative effects of pollution and other societal impacts.

Because CED has to include the costs of renewable energy and emission offsets in evaluating conservation programs, it is becoming easier to financially justify conservation programs.

DSM programs, generally result in lower costs of purchasing energy without any lost revenues, and therefore, are almost always easier to financially justify than conservation programs. For example, encouraging a manufacturing facility to operate at night, while using the same amount of energy, results in lower costs and greater revenues to the utility. This happens because the retail cost of off-peak energy is usually much higher than the revenue CED receives by selling the excess energy in the off-peak wholesale market. However, since no manufacturer would generally operate at night without some benefit, the lower costs of acquiring energy can be passed directly to the firm without impacting non-participating customers.

At this time, CED does not offer any standard DSM programs but has successfully negotiated several DSM projects for individual customers. In the past, CED did offer customers discounts for operating during off-peak periods but these programs have expired. As will be discussed below, because of the large amount of surplus off-peak energy generated by CED's resources, CED can offer low-cost energy to firms that are willing to shift their energy use to off-peak periods, reducing costs to both the participating customers and non-participating customers.

One of the important programs that CED would like to implement in the near future is a load shedding program that will compensate business customers to reduce load during periods of high system stress, such as when a transmission line or generator fails, and the CAISO asks LSE's to voluntarily reduce load in advance of issuing mandatory load shedding programs.

<u>Regulatory Requirements</u>

CED does have regulatory requirements under SB 2 to reduce total energy use by 5 percent through conservation programs by 2020. In addition, CED must meet annual conservation targets set by AB 2021. Compliance with these regulations is enforced by the CEC and CARB.

In 2007, AB 2021 established a California goal of reducing energy consumption by 10 percent by 2016. In 2011, CED's conservation target was about a 3,100 MWh reduction in energy use, increasing to over 4,500 MWh by 2020.

<u>CED Programs</u>

CED is currently offering the following conservation/DSM programs to residential and business customers in Colton:

Residential

- Energy Efficiency Upgrade Rebates

- AC Tune-Up (Pilot Program)
- Air Conditioner Upgrade and Replacement Program
- Refrigerator Replacement Program
- Residential Energy Audit Program
- Solar PV (Photovoltaic) Rebate Program
- Low Income Assistance and Medical Baseline Billing
- Level Pay Billing

Commercial/Industrial

- Lighting and Equipment Upgrade Rebates
- Online Energy Review for TOU accounts
- Commercial Energy Audit
- Keep Your Cool Program

Residential Program Details

Energy Efficiency Upgrade Rebates: CED offers varying rebates on a number of home energy efficiency improvements. Currently CED offers rebates on: Occupancy sensors, pool pumps, solar attic fans, whole house fans, room ACs and ceiling fans. Customers who participate in the rebate program will experience a reduction in their annual energy costs.

AC Tune-Up (Pilot Program): This program offers free preventative maintenance on residential customer AC units up to 5 tons in size. The program replaces filters, checks refrigerant levels and adjusts the AC unit to minimize seasonal air conditioning costs.

Air Conditioner Upgrade and Replacement Program: This program offers up to $150/ton rebate to replace a SEER 11 or lower AC system with a SEER 15 or higher AC system. Upgrading AC systems will significantly lower residential customer's energy costs.

Refrigerator Replacement Program: CED will provide a new ENERGY STAR refrigerator to replace an existing inefficient refrigerator to qualified customers for the low cost of $180. The customer is charged $15 a month for 12 consecutive months. To qualify for the new refrigerator, customers must have an older, inefficient refrigerator that CED can recycle. 149 customers have participated in the refrigerator replacement program since 2011. CED has saved 61,239,000 kWh annually and a lifetime savings of 612,390,000 kWh.

Residential Energy Audit: CED residential customers with energy usage of over 10,000 kWh annually can qualify to participate in a residential energy audit. Participants can be eligible for additional direct install opportunities depending on audit recommendations. For customers who previously participated in an energy audit in the past two years with over 10,000 kWh of usage they can participate in up to $500 of direct install measured recommendations.

Solar PV Rebate Program: CED offers a rebate to customers that install solar PV systems to serve their home energy needs. CED solar rebate program has generated 5,505,827 kWh/ year since the inception of the solar rebate program. Residential solar rebates will be reinstated beginning September 5th 2013 and commercial rebates will be reinstated beginning January 2, 2014.

Low Income Assistance and Medical Baseline Billing: CED also provides programs to help low income customers and those with medical conditions that require medical equipment to reduce their monthly energy bills. CED customers with qualifying medical conditions receive an adjustment to increase the baseline kilowatt hours on their utility bill. The baseline is increased so that the kilowatt hours that are used for life sustaining medical equipment are charged at a lower tier. These programs are not designed to conserve energy but instead recognize that the CED has an obligation to provide some level of financial assistance to low income customers.

In Fiscal year 2012/2013 CED had 2,148 low income customers participate in CED's once a year credit on electric charges. This allowed customers who received high bills during summer months, to receive up to a $150 credit to pay their electric bill. In FY 2012/2013, $254,702.46 was provided by the CED to low-income Colton residents.

Level Pay Plan: CED provides assistance to customers who are in need of stabilizing their energy bills. Residents with at least 13 months of utility service at their current address may choose to sign up to stabilize their energy bills and pay a consistent set dollar amount all year long. The dollar amount is based on the customer's annual consumption, on the 13 month is a true up.

Commercial/Industrial Program Details

The Commercial/Industrial Energy Rebate Program provides rebates to commercial/industrial customers that install new energy efficiency equipment from lighting upgrades to programs specific to the customer's business. The amount of the rebate depends upon the annual energy savings.

Lighting and Equipment upgrade rebates: Commercial and industrial buildings can benefit from substantial rebates given for improving lighting and equipment by increasing energy efficiency and lowering consumption. CED offer $.05 per kWh saved on the projected first year of savings.

Online Energy Review for TOU accounts: Automated energy is an online energy review CED offers to its TOU (Time of Use) customers. Automated energy provides access to specific interval meter data through their website.

Commercial Energy Audit: Small commercial businesses that use less than 30 kWh annually qualify to participate in CED commercial energy audit. Businesses can be eligible for additional direct install opportunities depending on audit recommendations. CED is offering $1,000 of direct install measured recommendations. This is a program to assist small businesses who are concerned with their energy consumption and want to learn how they can minimize their usage, shift their load, and save on energy costs.

Keep Your Cool Program: This program is a new program for FY2013/2014. Small commercial business that have inefficient refrigeration, lighting and cooling such as mini marts and fast food restaurants can benefit from participating in this program. CED will provide up to $3,000 per location in energy efficiency upgrades.

Measurement and Verification Activities

CED is required to have a third-party Metering and Verification (M&V) program to verify the claimed energy savings from different programs. Currently, E3, a California consulting firm certified by the CEC for conservation programs savings verification is used to verify savings and benefits. Alternative calculations may also be used for some measures.

Future Energy Efficiency Programs

CED is planning to implement the Living Wise Resource Action Program partnering with Colton Unified School District. The project plan includes the delivery of 340 Living Wise Kits to students who attend schools in Colton Electric's service area. As part of the program students and parents will install resource efficiency measure in their homes. Students and parents learn how to measure pre-existing devices to calculate saving that is generated by their efficiency upgrade. The goal of the program is to change customer behavior and experience energy savings from their actions.

Several of CED efficiency programs have come into fruition within the last 3 months. CED anticipates having more energy savings data available for residential and commercial programs by the 2014 Integrated Resource Plan. CED continues to work with the community and development the best energy efficiency programs with our customers' needs in mind.

Summary of Conservation and DSM Programs

CED's conservation programs have met State goals for 2010 energy savings but are significantly lagging to reach 2012 goals. In 2013 CED redesigned its Public Benefits Program and has significantly increased its outreach and offerings.

One of the things CED is studying is new DSM programs. CED should concentrate on cutting its on-peak demand and shifting energy from on to mid-peak periods. CED's peak loads exceed 70 MW for only 80 hours per year. But CED has to plan to meet this load at a cost of around $250,000 to $400,000 annually. By developing load shifting and interruptible load programs targeted at these few hours of the year, CED can lower it costs and reduce costs to both the participating and non-participating customers.

CED also has to ensure that its planned conservation and DSM programs are in compliance with the new SB 2 and AB 32 conservation requirements. Both SB 2 and AB 32 require CED to reduce energy by at least 5 percent by 2016. Because CED has concentrated on lighting programs in the past, it will be difficult to meet these new goals without working closely with local businesses and residential customers.

Energy Storage Programs

AB 2154 requires the CED to evaluate the cost effectiveness of energy storage programs, such as batteries, compressed air systems, Ice Bear small thermal energy storage systems and other ways of storing surplus energy, usually generated during the off-peak periods, to be used during high demand periods.

With the exception of hydroelectric pumped storage units that CED has been attempting to acquire since the mid-1990s, storage facilities are too expensive to be used for peak shaving.

CED has worked extensively with SCPPA to evaluate Ice Bear systems that use off-peak energy to create ice to reduce on-peak AC requirements. CED has determined that the Ice Bears are not cost-effective for its system.

At this time, it does not appear any smalls scale storage systems are cost effective and CED will continue following technological advances to see when small scale energy storage systems become cost effective.

Chapter 6
Risk Management

Introduction

As a small utility primarily concerned with meeting retail load requirements, CED generally assumes a risk-averse posture. CED prefers certainty in total power supply costs rather than risk upward price movements in the energy market. CED does not speculate in the energy market and attempts to purchase energy only to meet retail load requirements.

CED's exposure to risk comes in a number of ways. For example, CED faces forecast risk, market-price risk, regulatory risk, supply risk, counter-party risk and other types of business risk. A relatively new source of risk is the development of the MRTU market and transmission congestion price risk.

The single largest risk exposure that CED faces is a prolonged outage of SJ3. SJ3 provides over 65% of CED's annual energy requirements and 30 MW of monthly system RA capacity. Each month that SJ3 is out of service due to forced outages results in almost $800,000 in additional costs.

Forecast risk is the cost associated with over or under-forecasting CED's retail requirements and having either too much or too little energy that it needs to buy at higher than expected costs or sell energy from existing contracts at a loss;

Market-Price risk is the risk associated with entering into long-term contracts and then having the wholesale energy price fall such that CED could have purchased the energy less expensively. Conversely, if CED chooses not to enter into a contract at current prices and then prices rise, CED could be criticized for not locking in prices.

Regulatory risk is the added cost of changes in the regulatory process or new regulations that increase CED's cost of doing business. The greatest fear of regulatory risk is that CED takes actions to meet current regulations and then the regulations are changed in such a manner that CED incurs costs to both undo earlier actions and then has to spend money to meet the new regulations.

An example of regulatory risk is SJ3. In the late 1970's, utilities were prohibited from using natural gas for electricity generation. So CED, along with other SCPPA members, began investing in coal plants. 30 years later, natural gas is plentiful but the nation is concerned about air quality and Congress and EPA have implemented new laws and regulations intended to reduce emissions from coal-fired generation. CED, which had invested in coal generation, must now spend millions of dollars to mitigate the air quality impact of high emission coal resources.

Supply risk is the chance that contracted sources of energy is not delivered for any reason, resulting in CED having to incur additional costs to replace the energy. For example, each day that SJ3 is out of service results in CED incurring approximately $40,000 in additional energy costs.

Counter-Party risk is the risk that a counter-party defaults on its obligations and CED incurs a financial penalty attempting to replace energy contracted from the counter-party. To minimize this risk, CED attempts to insure that its counter-parties are financially sound and contractually bound to meet their supply obligations.

Transmission congestion risk is now one of CED's biggest concerns. CED has acquired generation resources and fuel supplies that meet most of its daily load requirements. However, other than through the acquisition of CRRs, CED cannot easily hedge its congestion risks.
CED cannot avoid risk. Daily or hourly energy requirements cannot be forecast with a high degree of certainty weeks or months in advance of need. Nor can CED cannot control the actions of its counter-parties or regulators.

Regardless of its inability to control the actions of the market or other entities, CED can design its resource acquisition strategy minimize the financial impact of forecast and market risk. CED has fixed the price of roughly 80 percent of its energy requirements for the next few years, attempting to minimize the impact of sudden price spikes in the power markets. CED only deals with companies that have good credit ratings and periodically reviews these ratings.

An area of concern to CED is regulatory risk. CED is having significant problems keeping current with GHG legislation, including new C&T and RPS requirements being implemented simultaneously. The implementation of the MRTU market structure, proposed new capacity market structures, RPS and energy efficiency requirements along with proposed new environmental rules are straining CED's ability to identify and comply with all the relevant regulatory requirements.

Development of a Risk Management Plan

Risk Management means limiting and reducing risk associated with CED's business activities that could result in economic loss. Risk management includes activities that identify, measure, assess, limit and reduce risk. As related to the use of derivatives, risk management means reducing risks in the broad sense of the term, including activities that select one type of risk over another when is considered more tolerable but it does not include activities that increase risk.

From a risk management perspective, CED's primary objective is to meet its retail energy and regulatory requirements. Power supply activities are focused around these objectives. Taking any unnecessary risk in order to arbitrage market opportunities or risks unrelated to CED's normal power supply business activities is considered inappropriate. Power transactions made with the sole intent of maximizing revenues could expose CED to unnecessary financial risks and are generally prohibited.

Risk management in this context is defined as financial risk management.

CED's primary mission is serving the electricity needs of CED's customers.

Specific objectives, listed in order of priority, to achieve this mission include:

1. Providing electric power to its customers through the use of CED's generation resources and wholesale natural gas and power purchases.
2. Providing a reliable supply of natural gas for CED's generation units to support the objective of providing reliable electric power.
3. Optimizing CED's generation and transmission resources to ensure that they are used in the most economical way resulting in the lowest possible price to CED's ratepayers.
4. Acquiring natural gas and wholesale power at prices that allow CED to maintain stable and competitive retail rates.
5. Given the reliability of supply of natural gas and stability of prices of natural gas and wholesale power as top priorities, obtaining the lowest reasonable natural gas and wholesale market prices.

Individuals or groups responsible for purchasing energy, capacity, natural gas and transmission for CED may not engage in activities that expose CED to speculative commodity trading risk. Any activities that are not related to CED's normal power supply business and have the effect, or potential, of increasing financial risk is to be avoided.

Speculative risk means any risk that is engaged in for its own sake and is not a business risk. For example, an exposure to fluctuations in energy future prices is considered speculative if a position is taken, for example a contract for natural gas or energy is purchased or sold, when there is no need or intent to deliver energy. A speculative risk is unrelated to production and delivery of electricity to CED's retail customers and could be avoided without any financial penalty to CED.

The Risk Management Policy (RMP) articulates CED's objectives, techniques and controls for managing such risks related to wholesale energy markets. The RMP scope covers all wholesale capacity, energy and natural gas contracts within or considered for CED's portfolio. Policy implementation, compliance and revision will be reviewed and approved by City's Management Services Director who will act as the Risk Management Officer.

To the extent feasible, given political, regulatory and environmental constraints, CED shall insure that the cost of its fuels, energy and related transmission resources shall remain competitive over the long term. Therefore, CED shall conduct its fuel and energy procurement in a manner necessary to compete successfully in the marketplace as a cost hedger. Fuel procurement activities will be conducted under the same risk management principles and procedures as power supply.

Organizational Structure

CED is a small organization that currently outsources the daily scheduling and communications with the CAISO. CED has hired Shell as its SC and Shell schedules CED's resources to meet daily forecasted load.

In a classic "front office – middle office – back office" organizational structure, Shell functions as the "front office," scheduling resources to meet load in conformance with applicable contracts.

Most of CED's resources are power purchase agreements or wheeling agreements with SCPPA. SCPPA is responsible for verifying the invoice from the project manager or owner and then each participant is responsible for verifying their share of the project monthly costs. SCPPA also invoices CED for its share of various natural gas purchases through SCPPA.

In addition to SCPPA, each month CED receives invoices from:

- Shell for all CAISO costs, including use of the CAISO controlled grid, ancillary services, the gas "floating for fixed" swap and the purchase and sale of imbalance energy;
- SCE for wheeling services over existing transmission paths and several customer service projects on behalf of CED;
- Colton Landfill for the purchase of up to 2 MW of renewable energy;
- The Cities of Burbank and LADWP for transmission service for MPP;
- Bureau of Reclamation and Department of Energy for CED's share of the Hoover Uprating Project;
- The City of Anaheim for the MWD energy swap;
- Management and operation costs of the AMPP.

Once an invoice is received, energy and costs are verified against monthly forecasts of power supply created as part of CED's annual budget review process.

As part of the middle office function, CED should verify total energy deliveries against load and verify that CED accounts for all energy purchases, generation and sales (energy balance).

The Colton Finance Department serves as the "back office." Only when invoices have been received and verified will the Finance Department issue a check for payment. No one in the front office (Shell) or middle office may issues checks for payment for power supply costs or expenses for CED.

At this time, CED does not have an internal counter-party policy. CED only purchases or sells to CAISO approved counter-parties or with entities approved by SCPPA and operates under the CAISO or SCPPA policies for counter-parties.

Colton's Management Services Director (MSD) acts as CED's Risk Management Officer. The MSD must agree with the expected financial impacts of any proposed long-term firm power supply purchase or hedging contract in excess of one year. In general, the MSD must verify that CED is entering into a power purchase agreement for the purpose of meeting load requirements and not for speculating in forward markets.

<u>Value at Risk</u>

The Value at Risk (VAR) is used by CED as a measure of power supply risk. The VAR is an estimate of the potential change in portfolio value (which may consist of several commodities such as electricity prices and natural gas prices) or cost parameters given a level of statistical confidence over a pre-defined holding period (day, month, year).

CED's targeted VAR is:

- CED will have a budget VaR of less than 5 percent of total energy and capacity costs at least one month ahead;
- CED will have a budget VaR of less than 10 percent of total capacity and energy costs prior to the beginning of the fiscal year;
- CED will have a budget VaR of less than 20 percent of total capacity and energy costs prior to the beginning of the second year.
- CED will have a budget VaR of less than 30 percent of total capacity and energy costs prior to the beginning of the third year.

CED's current resource mix satisfies its targeted VAR. CED's 2012-13 VAR is about 5 percent, or an increase in natural gas costs of 50 percent will result in an increase of about $1,500,000 in total power supply costs, primarily through increased costs of non-firm purchases in the CAISO market.

The greatest financial risk to CED is an extended outage of SJ3. Because of the take-or-pay requirements in the power purchase agreement with SCPPA, if SJ3 were to suffer an extended forced outage, the cost of replacement energy could be as much as $700,000 per month during the summer months and $500,000 per month during the winter months plus another $150,000 in replacement capacity costs.[14]

CED uses approximately 1,650 MMBTU/day of natural gas. Due to its pre-pay gas agreements and entitlement in the Pinedale and Barnett producing fields, CED does not have any significant exposure to increases in natural gas costs. On the other hand, CED does not benefit from declines in natural gas costs except through purchase in the CAISO marketplace.

Historically, one area that CED had little or no control over was congestion risk. CED has had several months since 2008 in which congestion costs exceeded $200,000 due to a high congestion costs from Phoenix to the Los Angeles basin, the transmission path used by SJ3. Since mid-2012 CED has been actively managing its congestion risk and has significantly reduced monthly congestion costs.

If Shell or CED realizes that a transmission path is constrained and congestion costs are greater than the SJ3 cost less the LMP, Shell has been instructed to attempt to minimize CED's use of that path in excess of CED's CRRs. In most cases, this means CED will generally pay one or two days of congestion before reducing schedules over a path.

The difficulty with transmission congestion is that the congestion costs are not known until after day-ahead bids are received by the CAISO. If congestion costs were known in advance, then entities could decide whether or not to use a congested path. But since congestion costs depend upon who is planning to use a transmission path, entities make their generation plans and then take the risk of congestion or manage the risk by acquiring CRRs.

[14] These costs are based upon a $50/MWh cost of replacement energy. At current natural gas price costs, the estimate would be about $400,000 during the summer and $275,000 during the low load months.

CED reviews all CAISO invoices on a daily basis as they are received from Shell verifies energy balances and CRR costs. CED also monitors changes to the invoices as the CAISO makes its periodic reruns of costs.

Summary of Risk Management Activities

In order to minimize CED's exposure to significant changes in power supply costs and to provide an additional layer of administrative review, CED has implemented a RMP. The primary components of the RMP include:

- Review by Colton's MSD of any long-term power supply purchases or firm power supply purchase exceeding $500,000 in any single month;
- Maximum monthly limits on CED's power supply VAR;
- Required review and verification of CED's monthly energy balance;
- Review of monthly congestion costs and CRR status;
- Review of monthly costs of EA's and verification that CED has sufficient EAs to cover expected annual emissions.

In December 2011, FERC issued FERC Order 741[15] requiring that all entities dealing in ISO's with congestion pricing verify that they are managing the risk of their congestion costs through a documented risk-management plan by April 1, 2012 and annually thereafter. CED has prepared and filed its RMP with the CAISO and agreed to perform the required periodic evaluations of market risk and congestion risk. The CAISO has accepted CED's 2012 and 2013 RMP filings.

[15] The Colton City Council approved filing the City's Order 741 response on June 3, 2012.

Chapter 7
Renewable Resources

Introduction

Renewable resources are resources that do not require fossil fuels to generate electricity. Renewable resources include solar, including both solar photovoltaic and solar thermal plants, wind, geothermal, biomass and biogas. A brief discussion of the pros and cons of each type of renewable resource is provided below. This Chapter discusses which renewable resources will minimize the rate impacts on CED's ratepayers of meeting RPS standards.

Solar Photovoltaic (PV)

PV is the most successful renewable resource. PV panels convert sunlight into direct current (DC) electricity and then an invertor system converts the DC energy to alternating current (AC) energy for use on the electric grid.

PV differs from solar thermal in that PV converts solar energy directly into electricity while solar thermal uses heat to power generators.

Five years ago PV was generally considered too expensive for use in large power generation facilities but a huge drop in price of price of solar panels due to over-capacity and a decline in new solar PV projects due to the world-wide recession has caused PV prices to decline by 20 to 30 percent.

As a result of the price decline in solar PV, a number of thermal solar projects have been re-engineered to use PV rather than the original solar thermal design.

PV generation usually begins around 0830 in the morning and reaches maximum output around 2 hours later. Output begins to decline around 1530 each afternoon and is usually not available by 1730 or earlier. Output varies significantly during the year with winter generation sometimes as little as 60 percent of maximum summer capacity.

Because many utilities, including CED, peak later in the day due to a combination of lighting load and air conditioning loads, solar PV is not always available during the highest use periods of the day. This means that a utility may require additional non-PV capacity available to meet its peak load requirements.

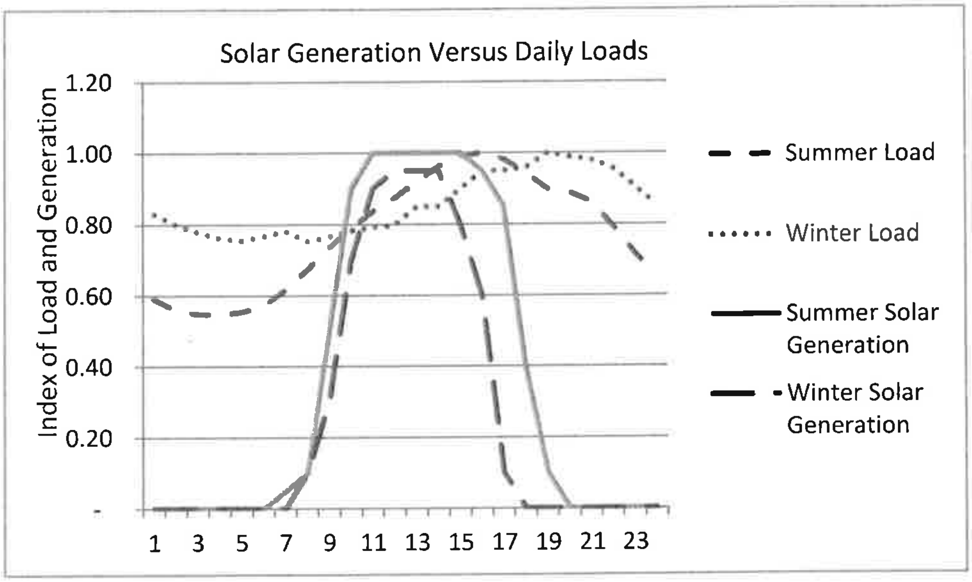


Figure 7.1: Index of Solar PV Generation versus Hourly Load

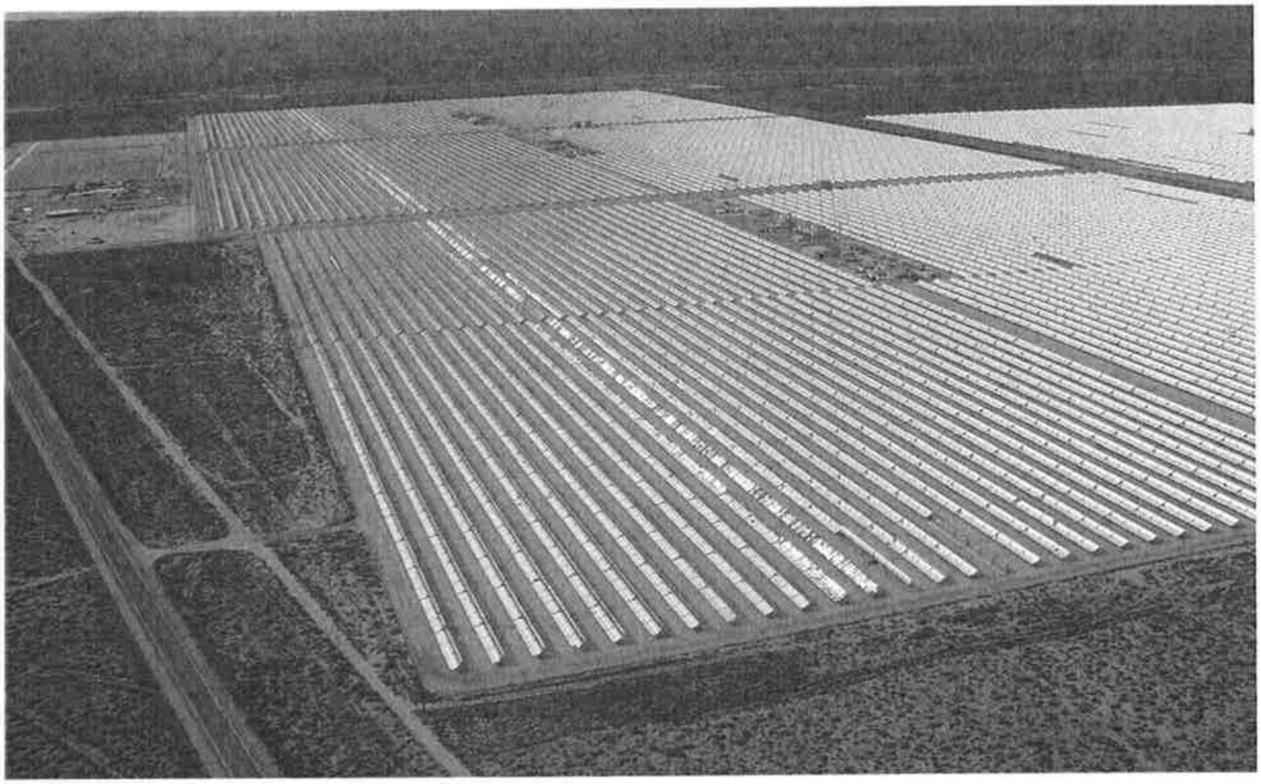
The above figure shows that during the summer months, PV generation begins to decline even as retail loads are high, resulting in CED having to keep additional thermal capacity available to meet loads. During the winter months the PV generation is not available at all during the peak periods (that occur later in the day). This mismatch of load requirements and generation reduces the value of PV to CED.

The greatest benefits of PV are that it can be constructed in small areas, is relatively inexpensive and generally does not create off-peak surplus energy.

<u>Solar Thermal</u>

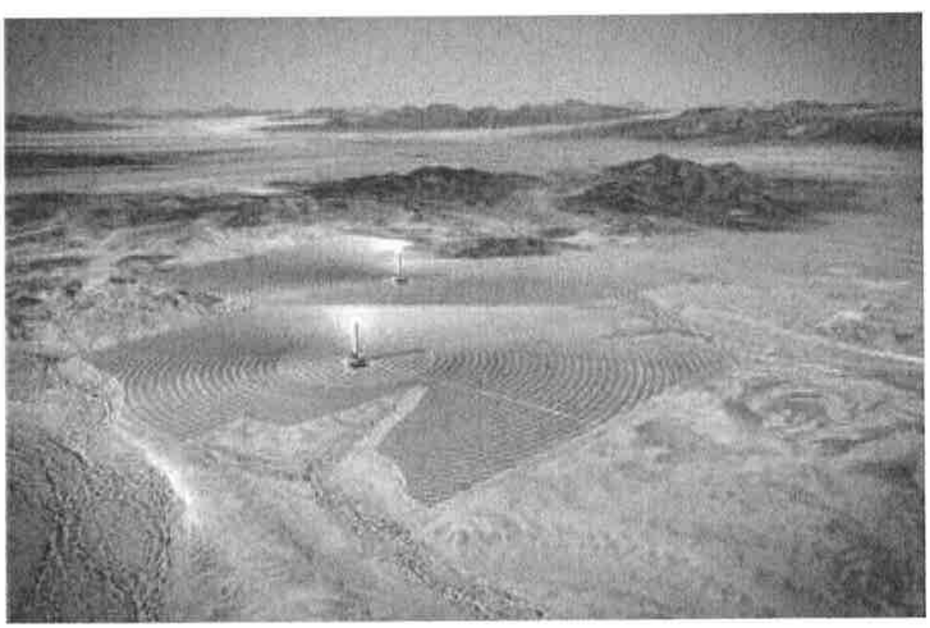
Solar thermal generation differs from PV in that sunlight is turned into heat that is then used to create steam and turn a turbine. Currently, there is more solar thermal generation in California than PV but that should change in a few years as more PV projects come online.

There are two major kinds of solar thermal generators. The Luz "trough" type, where high temperature oil is sent through pipe. Parabolic mirrors focus sunlight heating the oil to around 800 degrees which is then used to turn water into steam to power a generator. There are a number of these projects in the Barstow and Harper's Lake region of San Bernardino County.



The other type is SCE's Solar 2 project, unofficially known as a "steam on a stick" where an array of mirrors focuses sunlight on a small area that creates steam that is used to power the generator.

A picture of a proposed solar thermal project shows how the array of mirrors focuses the sunlight unto the top of a tower where the steam is created to power a generator.



Solar thermal projects tended to be larger than PV projects to justify the higher cost of generators but since the decline in PV prices, many of the solar thermal projects have been converted to PV.

Solar thermal projects tend to generate a bit later in the day than PV projects, making them more attractive as a capacity source since they become more coincident with utility peak loads.

Most new solar thermal projects have different kinds of heat storage, such as molten sodium, to extend the daily generation capabilities. While this makes it more useful in meeting evening peak loads, the additional costs also make solar thermal projects more expensive.

Wind

The expansion of wind energy is creating significant problems on the western transmission grid. If a large amount of wind generation is available, thermal resources have to remain available in the event the wind stops and generation drops significantly. Wind is inexpensive and generally abundant but the operational issues associated with it have not yet been fully resolved.

Wind energy has the greatest potential when paired with storage, including batteries, pumped storage or some other firming resource that reduces the moment to moment generation changes.

Small Hydroelectric

Hydroelectric facilities currently count as renewable resources only if they are smaller than 30 MW and do not interfere with run-of-river conditions (that is, no reservoirs or storage with a minor exception for small conduit generation from new reservoir construction).

There are a number of bills that attempt to count large hydroelectric generation as renewable but so far, none of them have passed the California legislature although large hydroelectric generation does count in federal RPS proposals (none of which have passed Congress).

The major problem with small hydroelectric facilities is that there are few places in California where new hydroelectric facilities can be constructed. California's hydroelectric production has actually declined over the past ten years as hydroelectric facilities have been taken out of service for environmental considerations.

Hydroelectric is a good source of energy especially when storage (such as pumped-storage) is included and energy can be dispatched to meet load requirements.

Biomass

Biomass generation is the production of energy using plant material, such as trees, plants, crop cuttings and other plant sources. There are only a few biomass generators in southern California mostly burning crop cuttings and dead trees remaining from the bark beetle infestation in the late 1990's – 2000's in the San Bernardino mountains.

Even though the raw resource is cheap, most of the facilities have very high costs due to the labor necessary to gather the fuel stock.

There is an ongoing attempt to develop a biomass facility using the sludge from the RIX facility, a system to inject reclaimed water into the local water basin for cleaning. It is not known if a project can ever be developed in light of the difficulty past projects have had getting the required permits from CARB and other state agencies.

Geothermal

CED is currently a participant in the development phase of a SCPPA geothermal project in Imperial County. Geothermal resources use high-temperature brine (300 – 700 degrees) created by underground lava flows as the heat source for generating electricity.

Imperial County has some of the best geothermal resources in the world and currently produces about 1,600 MW of geothermal energy, primarily for SCE and the Riverside Public Utilities Department.

The biggest problem with developing geothermal generation is that the brine is highly caustic and corrodes steel pipe in several months. As a result, tungsten and stainless steel pipe has to be used at very high cost (as much as $1,800 per foot) driving up the cost of production.

In addition, there is no guarantee that when a geothermal well is drilled that it will hit a viable brine source. Since each well costs about $10,000,000 to drill, the cost of drilling failures is very high and has prevented the geothermal industry from getting financing until the wells have been drilled and are producing. The high upfront drilling cost has slowed the development of geothermal energy in the western states.

Geothermal energy costs are between $90 and $115/MWh at current interest rates.

Biogas

Biogas is methane collected from the decomposition of plant and waste materials. There are a number of biogas facilities that use cow manure as the decomposing material and then collect the gas, remove impurities and inject the gas into the interstate pipeline system where it is burned in power plants.

Biogas is an inexpensive and easy way to meet RPS goals. In March 2012, the CEC suspended the use of biogas as a renewable fuel except for limited cases of landfill gas and digester gas. However, biogas that was injected into the interstate pipeline system does not currently count as a renewable fuel.

In the adopted version of the "RPS Guidebook" the CEC has approved biogas generation with a number of restrictions. Biogas can be used to meet RPS requirements if the biogas is produced within California, if the biogas can be cleaned and injected into the interstate pipeline system and the gas can be tracked to the generator. Biogas can also be used if it is burned onsite for generation with no alternative source of natural gas available to the site.

Energy from biogas costs between $70 and $90/MWh if used in a high-efficiency power plant (for example, the Magnolia project). If used as a fuel for AMPP, renewable energy would cost around $90-$99/MWh.

CED does purchase the biogas generation from the Colton landfill that collects gas from the decomposing waste and then uses IC engines to run generators. The generation is performed onsite because the gas is too polluted to be injected into the pipeline system.

Renewable Resources That Meet CED's Needs

CED does not currently need any additional baseload energy although by 2018 it will need approximately 15 MW of baseload generation. The renewable resources that appear to best meet CED's requirements are a combination of 13 to 15 MW of baseload generation (geothermal, biomass or biogas) and 15-20 MW of intermittent resources (wind, solar PV).

Even though wind generation does not have a significant capacity value, CED has a capacity source with AMPP and wind energy can be used to offset fossil fuel generation.

Biogas can be used as a fuel for either Magnolia or AMPP. If used at Magnolia, the cost of renewable energy will be around $70-$75/MWh (assuming $12/MMBTU of biogas) while AMPP would generate renewable energy at a cost between $90-99/MWh. The higher cost at AMPP is due to the higher heat rate of the unit compared to Magnolia.

. Finally, small PV projects within or near Colton would be the next most attractive renewable resource.

The following figure presents the range of costs of renewable resources in the market based upon SCPPA RFP's.

Technology	2009/10 RFP	2010/11 RFP	2011/12 RFP
Intermittent			
Solar thermal	$180 - $210	-	-
Wind	$55 - $115	$63 - $102	$57 - $73
Solar Photovoltaic	$115 - $210	$81 - $160	$65 - $146
Small Hydrogeneration	$50 - $100	-	-
Energy Storage	$90 - $120	-	-
Baseload			
Biomass	$100 - $150	$82 - $108	$95 - $116
Geothermal	$70 - $135	$90 - $110	$80 - $116
Biogas/ Landfill Gas	$84 - $110	$76 - $110	$92 - $103
Conventional Generation			
Simple Cycle	$230 - $250		
Combined Cycle	$75 - $145		

Table 7.1: Renewable Prices – Update based on latest SCPPA RFP

SB 2 established 3 compliance periods, 2011-2013, 2014-2016 and 2017-2020. During the first compliance period, utilities are required to meet a target of 20% of all retail sales to be provided by qualified renewable resources. During the second compliance period, 25% of all retail sales must come from renewable resources and by the end of the third compliance period, the minimum percentage of renewable resources is 33%. The CEC also instituted additional compliance targets during the third compliance period.

In addition to the minimum percentages of retail load met by renewable resources, renewable resources are further disaggregated to the type of renewable resources, with minimum amounts of each category required during each compliance period.

The first type of renewable resource category or Portfolio Content Category (PCC) is renewable resources located within California where the energy and green attributes are delivered to the utility for resale to its retail customers.

The second type of PCC is when an energy generation source (like wind or solar) that varies from hour to hour is delivered on an even basis during the day. Hourly fluctuations are usually made up by non-green generation but only the actual green energy can be counted towards RPS requirements.

The third type of PCC is Renewable Energy Credits (RECs), where a green provider produced green energy and sold the energy into a power pool, or to an end-user, and kept the green attributes. The renewable energy attributes, or RECs, can be registered and used for up to 3 years.

The CEC has also created a new category of PCC called PCCZero. This PCC covers renewable contracts entered into prior to 2010 and helps meet the total RPS requirement but does not count as a specific PCC renewable resource. Currently, all three of CED's renewable resources are categorized as PCCZero.

During the first compliance period, at least 50% of the renewable resources must be from PCC 1. The amount increases during the second period to 65% and then to 75% in the third compliance period.

While PCC 1 is increasing, PCC 3 is decreasing, declining from a maximum of 25% of RPS requirements in compliance period 1 to 15% in compliance period 2, and to 5% in compliance period 3. By 2017, RECs can only be used only to make up a small portion of RPS requirements.

The following table shows the maximum RECs (PCC3) and minimum California renewable energy (PCC1) amounts for each compliance period for the CED:

	CED Annual RPS Requirement	Existing PCCZero MWD	Colton LF	Iberdola	Total PCCZero	Remaining Requirements	Minimum PCC1	Maximum PCC3
2011	67,048	8,468	6,932	7,711	**23,111**	43,937	21,968	10,984
2012	68,242	8,124	6,570	7,421	22,115	46,127	23,064	11,532
2013	67,654	8,124	6,570	8,760	23,454	44,200	22,100	11,050
2014	85,463	8,124	6,570	8,760	23,454	62,009	40,306	9,301
2015	86,181	8,124	6,570	8,760	23,454	62,727	40,773	9,409
2016	87,043	8,124	6,570	8,760	23,454	63,589	41,333	9,538
2017	94,946	8,124	6,570	8,760	23,454	71,492	53,619	7,149
2018	102,999	8,124	6,570	8,760	23,454	79,545	59,659	7,955
2019	111,204	8,124	6,570	8,760	23,454	87,750	65,812	8,775
2020	119,562	8,124	6,570	8,760	23,454	96,108	72,081	9,611

Table 7.2: CED's Renewable Requirements by PCC

There is no maximum or minimum for PCC 2 so long as the energy in the other two categories meets their maximum or minimum compliance period obligation.

Current Status of CED Renewable Energy Efforts

CED currently has three renewable resources, a 1 MW wind energy purchase from the High Winds Project between Sacramento and San Francisco, a landfill gas generation project that produces up to 1.2 MW per hour, depending upon the production of biogas at the landfill, and a small hydroelectric purchase from the Metropolitan Water District (MWD). MWD historically produces at less than 1 MW per hour although production varies by season.

With its current renewable resources, CED has approximately 5% of its retail sales met by renewable resources although the purchase of RECs increases CED's renewable percentage to around 6%.

During the first compliance period, CED can use RECs to meet a portion of its RPS requirements. CED can purchase up to 25% of its actual renewable energy purchases. This equates to about 4,500 RECs per year for 2011, 2012 and 2013.

RPS Compliance Requirements

CED does have some discretion about how quickly it meets the SB 2 mandated goals. SB 2 also allows publicly owned utilities to set cost limitations on annual renewable procurement expenditures consistent with meeting the goals of SB 2.

To stay compliant with the cost limitation rules, CED must comply with a formalized CEC approval process of its renewable procurement plan.

The CEC must agree with the cost limitations adopted by the Colton City Council. In establishing the cost impact, the CEC will rely upon:

i) The most recent renewable energy procurement plan;
ii) Procurement expenditures that approximate the expected cost of building, owning and operating eligible renewable resources;

iii) The potential that some planned projects may be delayed or cancelled.

The CEC will ensure that the cost limitation is set at a level that avoids disproportionate rate impacts and that all costs of procurement are counted towards the procurement limitation.

However, the CED is not allowed to count any indirect costs including the loss due to the sale of excess energy.

In July 2013, the Colton City Council approved a Resolution establishing a Renewable Resource Procurement and Enforcement Policy. In this Resolution, the City Council approved becoming fully compliant with the RPS rules by 2018 upon the decommissioning of SJ3. Prior to 2018, the CED will begin acquiring renewable resources but attempting to minimize the cost of these renewable resources that are surplus to CED's retail load requirements.

CED will begin putting purchase agreements in place for renewable capacity and energy to replace the lost power from SJ3 beginning in 2018.

Western Renewable Energy Generation Information System (WREGIS)

Utilities in California, and the rest of the western states, use the WREGIS to keep track of renewable resources and the purchase and sale of RECs.

Every green generator is required to register their generation facility with WREGIS. All generation from the facility is them reported to WREGIS on an hourly basis. WREGIS is also responsible for auditing the reported generation values.

WREGIS treats generated electricity as having 2 components, an energy component and a renewable component. If the energy is sold as green energy, the renewable component is transferred to the purchaser. If the energy is sold as brown energy, the generator retains the environmental attribute and it becomes a REC.

WREGIS tracks the history of the REC from the hour it was produced until when it is retired for compliance purposes. If an entity has a compliance obligation of 1,000 MWh of green energy, it must retire 1,000 RECs that were generated during the appropriate compliance period. All RECs must be retired within 3 years of generation or else they expire with no value.

CED has an account with WREGIS through SCPPA. As CED purchases renewable energy, the REC is transferred from the producer's account to CED's account. In 2014, once CED purchases its maximum RECs, it will retire all the 2011 RECs as part of its compliance requirements.

While WREGIS tracks RECs, it does not track the California PCC. It is up to the individual utility to be able to prove that its resources satisfy the PCC restrictions of SB 2.

CED's Renewable Requirements and Potential Costs

The following figure provides an idea of how much renewable energy (in addition to its existing resources) CED needs in the future to meet its RPS requirements:

As the figure shows, in 2011 CED begins with a deficit of 39,000 MWh of renewable energy, with the deficit increasing to over 80,000 MWh by 2020.

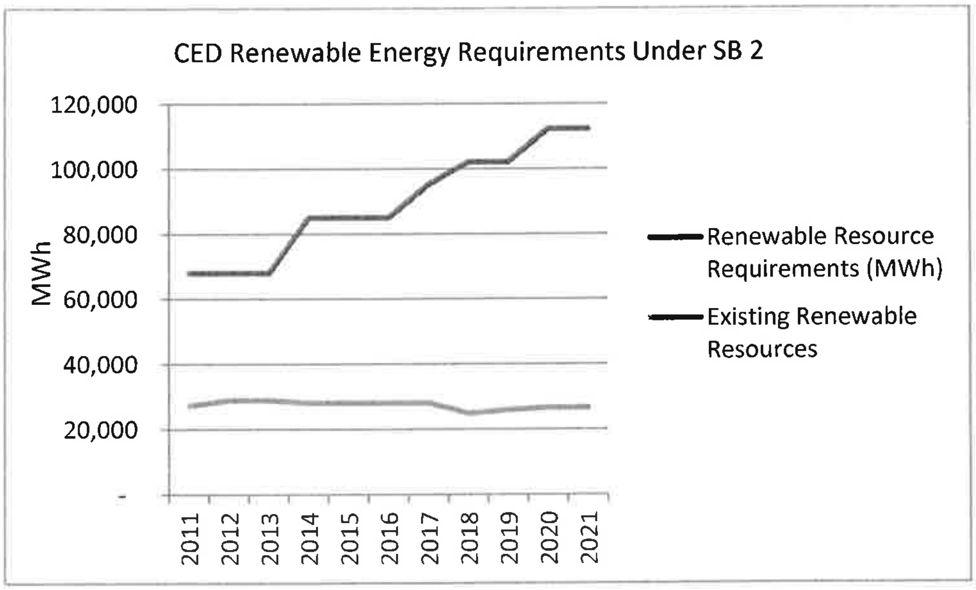


Figure 7.2: CED Renewable Energy Requirements

Also, CED's current renewable resources decline (as a percentage of total load) due to the reduction in allowed purchases in unbundled RECs in each compliance period.

An interesting aspect of renewable energy is that utilities that enter into PSAs will pay the developer high prices for the life of the PSA and then have to go out and negotiate new contracts at high prices. This is because the majority of a renewable resources cost is debt service. Once the debt is retired, renewable resources are very inexpensive, with only annual operations and maintenance costs.

But if a utility continues to purchase only the energy (as opposed to the project itself) it continues to pay for the debt of each generation resource, locking itself into a cycle of purchasing from resources with high energy costs.

If a utility purchases the renewable generation resource, once the debt is retired the cost of the renewable resource is very low and renewable resources can help lower long-term power supply costs.

In California, a general statement would be the large utilities (SCE, PG&E, SDG&E, LADWP and SMUD) are purchasing renewable resources while the smaller utilities are entering into long-term PPAs.

By acquiring renewable resources in a slow, planned phase-in, CED can minimize the cost of acquiring renewable resources to its ratepayers, meet SB 2 requirements and have time to develop a comprehensive long-term RPS strategy that has a small impact on CED's retail ratepayers. This proposal would meet the Colton City Council's cost-limitation criteria established in R-103-11.

Chapter 8
Generation Resource Planning

Introduction

The previous sections of the IRP have identified CED's existing generation and transmission resources, conservation and DSM programs helping meet CED's loads. In addition, the legislative and regulatory requirements that CED must meet in the next few years have been identified and the additional constraints they put on the resource planning process.

In this Chapter, the costs of meeting CED's loads will be forecasted under a variety of different planning assumptions.

First, a base case will be identified that is meeting forecasted loads with no change in CED's current generation resources. This scenario will identify the deficit CED faces in meeting the legislative and regulatory requirements of AB 32 and RPS requirements and the impact of the SJ3 decommissioning in 2017.

An important point to recognize is that although CED's budgeted power supply costs do not include debt service costs associated with AMPP they are accounted for in the power supply simulations. The annual debt service of around $2,900,000 for AMPP is accounted for in the City's debt costs and is not treated explicitly as a power supply cost for budgetary purposes; however, when doing a power supply analysis, all costs of power supply, including debt, should be considered in power supply costs.

Load Duration Curve

CED's load duration curve was calculated as a screening tool for the planning scenarios. The load duration curve ranks CED's 8,784[16] hourly loads from highest to lowest and then shows what portion of load is met by each type of resource, baseload, peaking or intermediate.

The load duration curve shows that CED's 45 MW of baseload generation (Magnolia, SJ3, Colton Landfill, High Winds and PVNGS) meets all of retail load requirements in all but 3,120 hours per year and generates as much as 39,000 MWh of surplus energy during this time, mostly during the off-peak periods.

For the load during the highest 3,000 hours of the year, CED relies on energy from Hoover, AMPP and market purchases for peaking and intermediate requirements.

The load duration curve also shows that that CED's peak loads only exceed 70 MW for about 200 hours per year. If conservation and DSM programs can reduce peak loads by 10 MW, CED can reduce the cost of meeting retail requirements between $250,000 and $400,000 annually. The majority of the savings

[16] 2012 is a leap year with 24 more hours than usual

would be due to reduced RA requirements with the remainder due to energy prices that are usually greatest during Colton's high load periods.

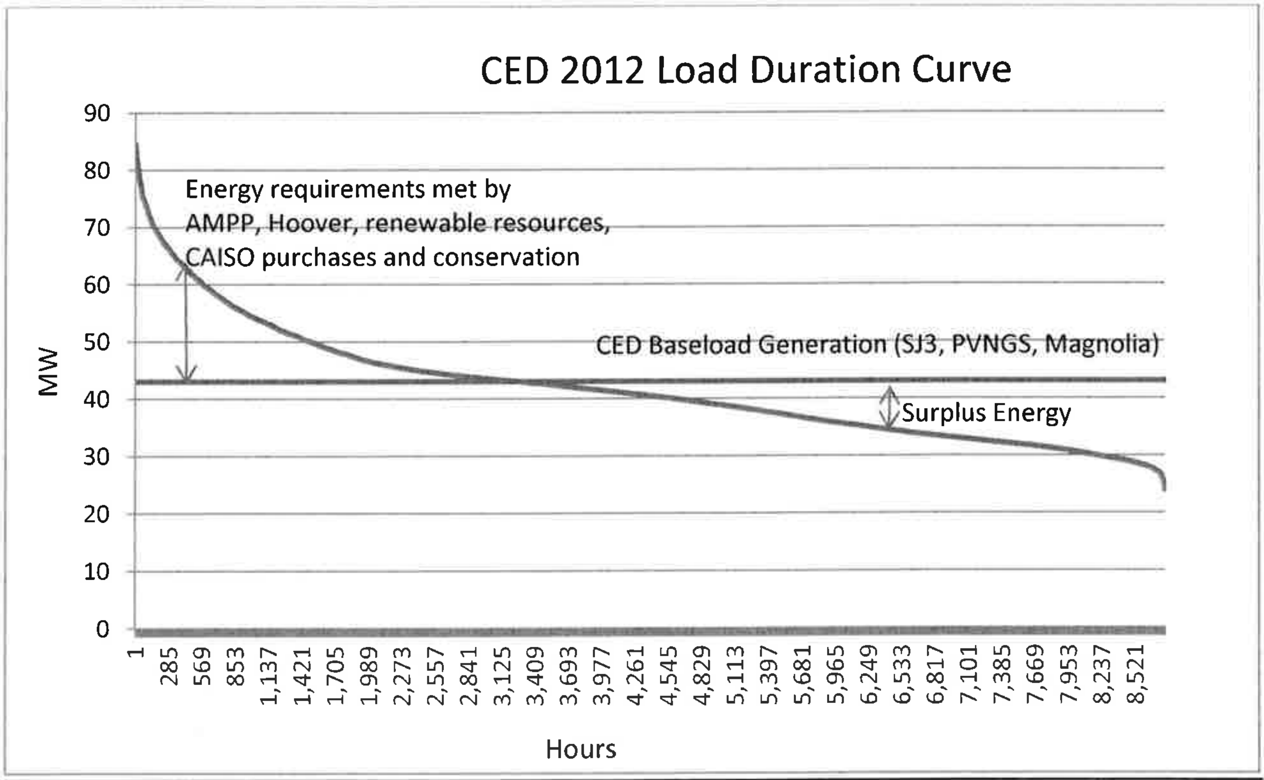


Figure 8.1: CED's Load Duration Curve

Base Case Scenario

The base case scenario examines CED's power supply costs with only existing resources and the demand and energy forecast prepared using the model presented in Chapter 2. The simulation extends only through FY 2018/19 to include the first year of the SJ3 decommissioning. The simulation does not include any additional conservation or DSM measures to attempt to reduce CED's monthly peak demands beyond the current programs.

SCPPA budget projections for the period 2013/14 through 2018/19 were used in the simulations.

For 2013/14, total power supply costs are $37.9 million or $101/MWh.

In 2014/15 total power supply costs decline to $35.2 million ($93/MWh) because of two primary factors, the end of the Shell natural gas hedge agreement and a decline in SJ3 costs.

The Shell hedge agreement was executed in 2010 as a means for CED to protect itself against rapidly rising natural gas costs. However, when natural gas prices plunged in late 2010, CED began paying Shell up to $900,000 annually. The hedge contract ends in May 2014 and CED will be exposed to a rapid rise in natural gas costs. CED would like to hedge its natural gas costs at today's lower prices but finding a counter-party to offer a hedge in the post Dodd-Franks world (with restrictions on offering financial hedges) will be difficult.

SJ3 costs will decline significantly in 2014/15 compared to 2013/14 because of reduced O&M at the facility and reduced environmental compliance costs because the cost of future environmental compliance will be borne by the remaining owners.

There is some uncertainty about the future level of SJ3 costs as the participants continue to negotiate the terms of the California entities exit from the facility. It is more likely that if SCPPA agrees to any additional costs, the impact will be relatively small and begin after the plant decommissioning.

In the 2015/16 and 2016/17 time period, costs remain relatively stable as forecasted growth keeps power supply costs essentially stable.

With the retirement of SJ3 in late 2017, power supply costs jump by more than 13% as CED has to purchase significant amounts of replacement capacity and energy to balance the loss of 30 MW of SJ3 generation. Much of the increase is due to having to purchase RA capacity while the remainder is due to replacement energy requirements.

By 2018/19 CED's costs are approximately $41 million or $106/MWH some 5% above current levels.

CED also has a significant financial risk in 2017 due to the pending SJ3 decommissioning. If there are any significant mechanical issues at the plant, the participants may decide to shut the plant earlier than scheduled rather than fix the problem. In this case, CED would have to acquire replacement capacity and energy. Replacement capacity could cost as much $150,000 per month while 30 MW of energy for all hours of the month would cost as much as $1.1 million monthly (at a price of $50/MWh).

That is, a forced outage in late 2016 or 2017 could have a major impact on the financial health of CED.

There are not many alternatives for hedging against this contingency. CED does not want to acquire too many surplus resources in advance of need nor can CED take the chance of going for an entire year having to purchase replacement capacity and energy for SJ3. The least expensive alternative appears to be entering into a 10 -15 MW renewable energy purchase in early 2017 and planning to sell surplus energy into the CAISO market during 2017. CED would only be short capacity for a few summer months and AMPP could be used to provide a physical hedge against the energy market.

The following table shows CED's actual and forecasted costs from FY 2012/13 through 2018/19.

RPS Simulation

The base case includes CED's existing renewable resources and an additional 5 MW (approximately) of solar development within the City. This new solar development is the result of an RFP that was issued by the CED in late 2012 requesting proposals for new solar projects in 2014. Including CED's existing renewable resources, CED would have approximately 40,000 MWh annual of renewable energy or about 11% of its load meet by renewable sources compared to the required 25 percent for the period 2014-16.

Renewable Case

The renewable case includes CED's existing generation resources plus the 5 MW of solar PV generation coming online in 2014 plus an additional 6 MW of solar PV generation in 2016 plus a new 10 MW baseload renewable purchase beginning in late 2017.

The proposed 6 MW of solar PV in 2016 is a purchase from a new solar PV farm located near, but not within, Colton.

In addition to the 5 MW of solar PV planned in 2014 for construction within the City, CED would have about 11 MW of solar PV in addition to its landfill gas, wind and small hydroelectric generation.

Baseload Renewable Alternatives

In order to meet the RPS requirements by 2018 and replace the capacity and energy lost due to the decommissioning of SJ3, CED requires a 10 – 13 MW baseload renewable purchase in the 2017 – 2018 time period. There are only three types of baseload renewable resources – geothermal, biogas (including landfill gas generation) and biomass. CED is studying purchases from all three sources.

CED would prefer a 1,500 MMBTU/day purchase of biogas that qualifies as an in-state source. CED is currently discussing alternatives with several biogas producers but at this time does not have a preferred supplier in place or formal negotiations with any potential supplier. CED does intend to issue an RFP in 2014 for biogas supplies beginning in early/mid-2017 for use at the Magnolia power plant.

SCPPA issued an RFP for renewable resources in 2012. Responses to this RFP included a number of baseload renewable resources including geothermal, biogas and landfill gas proposals.

Geothermal

Even though the Imperial Valley is one of best sources of geothermal energy in the world, transmission constraints have restricted the amount of geothermal energy available for export west to the LA basin and San Diego. The CAISO and SCE have agreed to upgrade the transmission capacity from the Palm Springs area west to the LA basin making more geothermal resources available in the 2019 -2020 time frame.

Prior to the 2019 – 2020 timeframe, much of the geothermal energy offered to SCPPA included generation from the Geysers facilities north of San Francisco and facilities in Nevada (Reno area). Prices from the Geysers facilities range from $85 - 95/MWh.

Geothermal energy produced in the Imperial Valley after 2019 ranges in cost from $90 - $100/MWh. The timeframe is dependent upon completion of new transmission facilities from the Palm Springs area into the LA basin (the "west of Devers" upgrades).

Biogas

SCPPA did not request a biogas alternative (at the time of the RFP, the CEC had suspended the use of biogas to meet RPS requirements). However, a number of landfill gas generators responded, offering landfill gas generation for around $90 - 93/MWh.

The difference between landfill gas generation and biogas is that the biogas is used onsite for generation with no need to clean the gas to interstate pipeline quality. Generally, the heat rate of landfill gas generators is poor, since only reciprocating engines able to use the poor quality landfill gas, but using the gas onsite allows the owner to minimize capital costs.

Biogas used by Magnolia will be less expensive than landfill gas generation primarily due to the high efficiency of Magnolia at current prices. However, new biogas projects may be more expensive than current landfill gas projects, making landfill gas generation and biogas roughly equal in price.

Biomass Generation

SCPPA did not receive any bids for biomass generation in the latest round of RFP responses. CED is discussing the possibility of a PPA with an existing biomass generator in northern California that anticipates having unsold generation in the 2017 timeframe. At this time, discussions have not dealt with pricing levels, although the generator has indicated a preference for index based pricing as opposed to a fixed price.

Summary of Baseload Renewable Purchase Alternatives

CED is currently looking at the range of proposals for baseload renewable energy in the 2017-2019 timeframe. However, so is every other LSE in California since LSE's must have baseload resources to meet the RPS requirements.

Once the west of Devers transmission upgrades are completed in 2018/19, there will be geothermal resources available for around $95 - 98/MWh. Prior to then, CED is talking to a number of biogas producers and landfill generators hoping to find financially attractive alternatives.

Simulation Results

For 2013/14, both the baseline simulation and the renewable simulation have the same resource mix and so costs are the same with total power supply costs of $37.9 million and $101/MWh.

In 2014/15 CED brings on a small amount of solar PV projects (roughly 3 to 5 MW) but enough that the additional capacity reduces CED's needs to participate in the summer RA market. As a result, CED's total power supply costs decline very slightly in comparison to the baseline simulation even though energy costs increase slightly.

In 2015/16 CED brings online another 3 MW of solar PV generation. This project actually has energy costs less expensive than summer peaking energy, resulting in another slight decrease in the average cost of energy.

The next increase in renewable generation is in 2017 when CED brings a baseload renewable resource online in January 2017, some 6 to 12 months earlier than needed to ensure that CED has sufficient RA capacity and energy in the event of an early shut-down of SJ3. The additional cost is almost $630,000 per month or as much as $7.2 million in additional costs. CED will attempt to "fine-tune" the timing of the power purchase as more information becomes available about the status of SJ3.

Even with the baseload renewable purchase, CED will have to purchase additional RA capacity at a cost of around $40,000 per month beginning in 2018. However, CED's energy purchases from the CAISO will decline significantly and CED will have little on-peak surplus energy once SJ3 is decommissioned.

CED's costs in 2017/18 increase some $300,000 compared to the baseline scenario due to the amount of surplus energy it is generating. But by 2018/19 CED's total power supply costs are less than the baseline scenario as SJ3 costs end and renewable generation begins replacing SJ3 generation. CED's renewable percentage increases to around 30% by the end of 2018.

The analysis assumed that CED would be able to purchase biogas and use it for Magnolia generation at an initial cost of around $85/MWh or around 12.50/MMBTU. If CED had to purchase more expensive biogas or landfill gas (or even geothermal) at a cost of $95/MWh, the additional cost would be about $800,000 annually.

Full RPS Compliance Simulation

The full compliance simulation assumes that CED acquires the resource mix shown in the renewables simulation and makes short-term purchases to come into full compliance with SB 2. No new long-term resources are purchased and the intent is to just identify the rough magnitude of costs CED will incur in meeting RPS obligations.

The simulation suggests that if CED had to come into full compliance prior to the decommissioning of SJ3, its power supply costs would increase by over $4.0 million annually in 2015/16 and 2016/17 to become RPS compliant at a cost of $30/REC. However, by 2018/19 the cost would be less than $1.5 million as CED increased its purchase of RPS resources. A portion, if not all, of these costs would be offset by the sale of surplus EAs after January 2018.

There is a question of whether the ARB will attempt to pull back any freely allocated allowances if a utility decommissions a generating plant. While CED believes that this is unlikely, it will have to continue watching how the ARB responds to any attempt to change the annual allocation of EAs.

Renewable Portfolio Simulation with 8 MW Generator

As an alternative to purchasing RA capacity and energy in the CAISO marketplace, CED could construct an 8 MW (net) Wartsilia reciprocating generator at the AMPP site, increasing in-city generation by another 8 MW.

The Wartsilia generator costs about $8.5 million and has a heat rate of approximately 8,300 BTUs/kWh. At a natural gas price of $5/MMBTU it can produce energy at $41.50/MWh. With a capacity cost of

$7.10/kW-month and O&M costs of around $5/MWh, the Wartsilia can generate at a total cost of about $59/MWh.

The capacity cost is about $7.10/kW-month, or about $16,000 more per month than the current cost of RA capacity in the market.

The advantage of the generator is that it would cap CAISO costs at $41.50/MWh in energy costs during the on-peak period. CED would have almost 60 MW of in-city generation and would likely not need additional capacity or energy for the immediate future. CED would also avoid any congestion costs associated with generation in other parts of the state.

CED appears to have sufficient excess air pollution credits that were originally purchased for AMPP that could be used to meet the Wartsilia pollution credit requirements.

The question is whether to purchase a 10 MW must-take resource (with RA capacity) or construct a new generator. It is not clear at this time which is the most economical alternative.

CED should at least submit the resource as a possible alternative into the CAISO interconnection queue in March 2014 to see what issues it would have interconnecting the unit with the CAISO grid.

Simulation Results

The 10 MW baseload gas generator was added to the renewable resources modeled above beginning in 2018. As a result, total power supply costs decline as the energy savings due to the generator result in savings of almost $1.0 million annually and RA costs decline although the capital cost of the Wartsilia generator results in higher total capacity costs.

The Wartsilia generator also allows CED to arbitrage the energy market, potentially turning the generator off during periods of low energy prices and generating when CAISO energy costs are high.

Energy savings are slightly more than $100,000 per month with the generator and annual RA savings are around $180,000.

With the generator, CED's costs per MWh are roughly equal to 2013/14 costs at around $101/MWh and around $3/MWh less than the renewable scenario.

Summary of Power Supply Simulations

In effect, by entering into a PPA for a 10 MW baseload renewable energy purchase, a 3 MW solar PV purchase and a 10 MW gas-fired generator, CED can transition from a coal based utility in 2013 to a 30% renewable energy based utility by 2018 with no impact on rates. CED will significantly reduce its congestion risks and likely be able to exit the emission allowance market because its freely allocated emission allowances are greater than forecasted emissions.

CED's primary risk exposure will be in the natural gas markets although the natural gas market is easier to hedge or enter into longer term contracts than the electricity market.

CED also does not have to construct a new 10 MW generator although it is less expensive than entering into a power purchase agreement. With ownership of a new generator, CED has the ability to turn off the generator when energy prices are low and purchase in the marketplace. When CED enters into a PPA for energy, it must purchase the energy even when prices are low.

The following figure shows power supply costs under the 3 planning scenarios. The simulation results are shown in Appendix C.

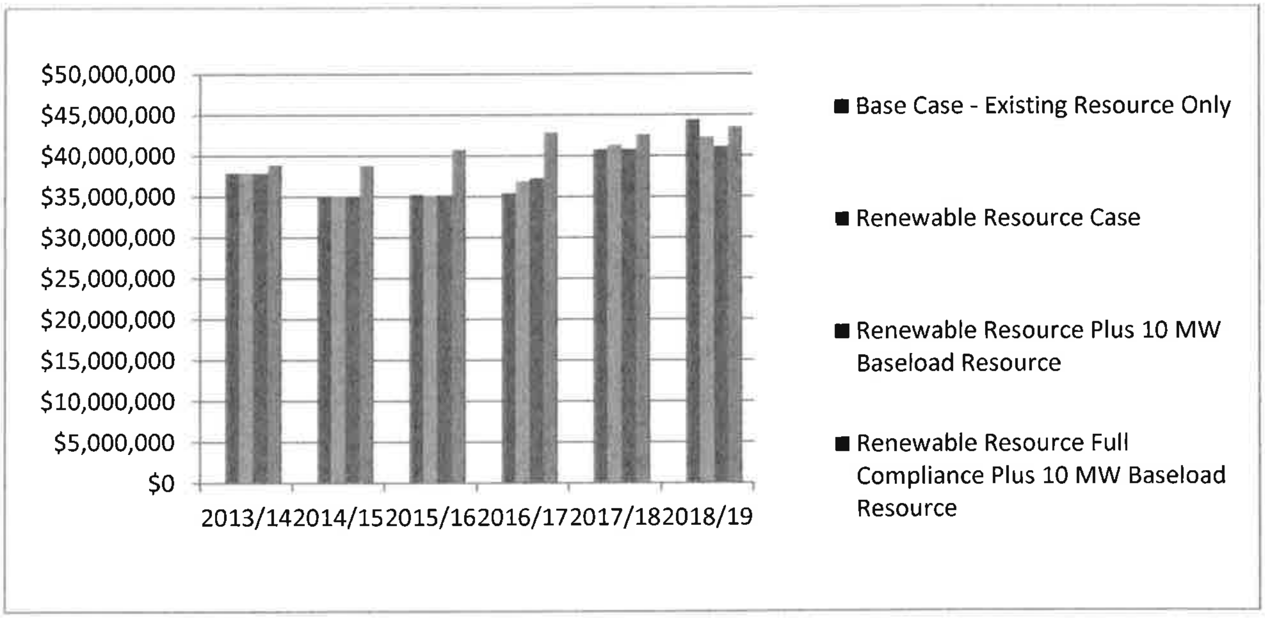


Figure 8.2: Power Supply Simulations Summary

As the above figure indicates, power supply costs are almost 10% less expensive in the renewable case with a baseload resource than in the base case of purchasing from the CAISO. In addition, the last scenario is consistent with state RPS requirements while purchasing from the CAISO is not.

These simulations do not include the value of excess EAs that CED may be able to sell and a few years of CRRs that may have some value once SJ3 is decommissioned since there is no way to accurately value them at this time.

Summary

CED will have to make relatively quick decisions on how to replace the energy lost due the decommissioning of SJ3. These decisions will be made at the same time capacity and energy from the now decommissioned San Onofre Nuclear Generation Station and a number of other California coastal generation plants has to be replaced.

CED must also come into compliance with RPS and GHG emission reduction requirements without significantly impacting customer rates.

The resource plan presented above meets future retail load requirements, meets CED's RPS and GHG emission reduction requirements and keeps retail rates close to current levels.

But there are still a number of issues that must be addressed. Most importantly, how to time the purchase of these new resources so that by 2018 CED is in compliance and has the ability to meet retail load without having significant surplus energy, and unnecessarily high, retail rates in 2016 and 2017.

Appendix A

Glossary of Terms

Arbitrage: The risk-free exploitation of temporary market price anomalies in related commodities or instruments, generally by the purchase of a commodity or instrument that is relatively low in price and the sale of the commodity or instrument that is relatively high priced. In order to be market neutral, the purchase and sale of the commodities or instruments should be simultaneous.

Call Option: An option that gives the buyer (holder) the right, but not the obligation, to buy a futures contract (enter into a long futures position) for a specified price within a specified period of time in exchange for a one-time premium payment. It obligates the seller (writer) of an option to sell the underlying futures contract (enter into a short futures position) at the designated price, should the option be exercised.

Cost VaR (Value at Risk): Cost VaR summarizes the expected maximum "cost" exposure over a target horizon with a given confidence level. For example, if trends indicate that an expected (or average) cost is $100 but volatility indicates that this cost may fluctuate wildly, VaR will capture the magnitude of this volatility as a summary number. This number, or estimate, can then be added to average or expected cost in order to measure the impact of volatility on potential cost.

Counterparty: A party on either side of a transaction (i.e. purchasing counterparty as opposed to a selling counterparty). External transacting parties such as the CAISO and NYMEX are not included in calculating counterparty credit exposures.

Counterparty VaR: the dollar estimate of the risk that subsequent changes in market price will result in increased counterparty credit exposure.

CO2e: Carbon dioxide equivalent emissions. The total impact of all emissions measured in terms of the equivalent amount of CO2 that has the same environmental effect.

Credit VaR: The statistical estimate of potential losses in a portfolio due to changes in counterparty credit ratings.

Derivative: Any financial instrument, such as a future contract, swap or option, which derives its value from the value of an underlying security or physical commodity.

Discretionary resource: Resources that are flexible in their dispatch and, as a result, are often managed as options in the sense that they may or may not be scheduled for dispatch. Discretionary resources contain less contractual scheduling limitations than must-take resources.

Displacement: The replacement of one generation resource with the matching amount of another competitively priced resource. Displacements provide for economic optimization of discretionary resources.

Electric Capacity: The maximum amount of electric power available for generation or use, usually expressed in kilowatts (kW) or megawatts (MW).

Electrical Energy: The generation or use of electric power over some period, usually expressed in megawatthours (MWh), kilowatthours (kWh) or gigawatthours (GWh).

Exercise Price: Also known as the strike price. The price at which futures are brought or sold if an option is exercised.

Least Cost Supply Portfolio: the mix of resources which optimizes the cost/risk profile of the utility. For example, if the utility is risk adverse, a lest-cost supply mix may have a higher cost than a supply mix that exposes the utility to greater fluctuations in volatility and reliability.

Load balancing: Meeting fluctuations in demand for power.

Load Management: Economic reduction of electric energy demand during a utility's peak generating periods. Load management differs from conservation in that load management strategies shift the use of energy while conservation programs reduce the demand for energy.

Optimization: The process of utilizing strategies and instruments to optimize economic benefits associated with load and resource management. Optimization differs from trading in that the strategic rationale for a transaction is the driver rather than the economic benefit alone. Trading functions are designed to form a commodity position with the intent of speculating on market arbitrage opportunities.

Option: A contract that gives the holder the right, but not the obligation, to purchase or sell the underlying commodity at a specified price during a specified time period.

Premium: The price of an option.

Prompt Month: The month following the current operating month.

Put Option: An option that gives the buyer, or holder of the contract, the right but not the obligation to sell a futures contract at a specific price during a specific time period in exchange for a one-time premium payment. It obligates the seller, or writer, of the option to buy the underlying futures contract at the designated price should the option be exercised at that price.

SCPPA – the Southern California Public Power Authority, a joint power agency that finanaces generation and transmission projects for its members, including the City of Colton. The member agencies are Los Angeles Department of Water and Power and cities of Glendale, Burbank, Pasadena, Anaheim, Riverside, Colton, Cerritos, Banning and Azusa along with the Imperial Irrigation District.

Speculation: The taking of an unhedged position (short or long) with the intent of holding the position in anticipation of changes in market prices.

Stop-Loss: A benchmark or "trigger" point at which a position will either be covered or closed. If a position is "out of the money" the amount "out of the money" will be limited by a stop-loss limitation. For example, if a stop-loss limit is $100,000, a corresponding position should be covered or closed if it is out of the money $100,000 or more.

Supply Requirements: Those requirements related to reliability and reserve standards mandated by the requirements of regulatory agencies of competent jurisdictions.

Swap: A custom-tailored, individually negotiated transaction designed to manage financial risk. In a typical commodity or price swap parties exchange payments based upon the change in the price of a commodity or market index while fixing the price they effectively pay for the physical commodity. The transaction enables each party to manage exposure to commodity price or index values. Settlements are made in cash.

Transaction Liquidity: The existence of sufficient volume of transactions of a particular product and commodity that generally assures a party's ability to locate a counterparty that is willing to either buy or sell the product in question.

Uncovered Option: An option on an underlying asset for which the seller is not long (in the case of a call option) or short (in the case of a put option) the underlying commodity.

Underlying Commodity: The commodity upon which the value of a derivative is dependent.

Volatility: The magnitude and frequency of changes in prices over time. Standard deviation is a measure of volatility.

Wheeling: In the electric market wheeling refers to the interstate or intrastate sale of electricity or the transmission of power from one system to another

WECC: The Western Electric Coordinating Council a regional reliability council created and recognized by the North America Electric Reliability Council is responsible for establishing guidelines and procedures related to the reliable electric operation of the 11 western U.S. states as well as parts of Canada and Mexico.

WSPP: The Western Systems Power Pool is a power pool comprised of most western utilities and power marketers. A significant development of WSPP is the WSPP agreement, a standardized enabling agreement, or master contract, utilized by over 200 utilities, marketers and other entities across the U.S.

Appendix B
Colton Electric Department 2012-2013 Demand and Energy Forecast

Year	Month	Forecasted Load (GWh)	Actual Load (GWh)	Forecasted Peak (MW)	Actual Peak (MW)
2012	Jan	26.6	27.4	46	46.7
2012	Feb	26.8	25.7	51	46.7
2012	Mar	26.8	27.2	49	46.5
2012	Apr	27.6	27.0	57	54.2
2012	May	31.9	30.3	67	65.6
2012	Jun	31.0	30.9	67	62.5
2012	Jul	40.1	35.5	83	75.3
2012	Aug	37.7	41.0	81	84.5
2012	Sep	37.2	36.4	77	76.1
2012	Oct	28.9	30.9	62	75.7
2012	Nov	27.6	26.7	54	52.8
2012	Dec	26.9	27.5	47	47.8
2012	TOTAL	369.1	366.5	88	84.5

Year	Month	Forecasted Load (GWh)	Actual Load (GWh)	Forecasted Peak (MW)	Actual Peak (MW)
2013	Jan	26.7	28.1	46	50
2013	Feb	26.9	24.8	51	48
2013	Mar	27.0	27.0	49	48
2013	Apr	27.9	27.3	57	52
2013	May	32.1	30.5	67	69
2013	Jun	31.2	32.1	67	73
2013	Jul	40.3	36.7	84	75
2013	Aug	38.1	36.9	82	80
2013	Sep	37.6		78	
2013	Oct	29.2		62	
2013	Nov	27.9		55	
2013	Dec	27.2		47	
2013	TOTAL	372.2		89	

APPENDIX C
Summary of Power Supply Simulations

Base Case

	Total Power Supply Costs $	Cost/Mwh	Change in total cost from preceeding year
2013/14	37,911,320	101.2	
2014/15	35,151,974	93.4	(2,759,346)
2015/16	35,198,008	93.0	46,033
2016/17	35,376,342	92.7	178,334
2017/18	40,832,293	106.0	5,455,952
2018/19	44,158,945	113.6	3,326,652

Renewable Resource Case

	Total Power Supply Costs $	Cost/Mwh	Change in total cost from preceeding year
2013/14	37,911,320	101.2	
2014/15	35,081,567	93.2	(2,829,753)
2015/16	34,998,256	92.5	(83,311)
2016/17	34,950,732	91.6	(47,524)
2017/18	40,747,170	105.8	5,796,438
2018/19	41,704,193	107	957,023

Renewable Resource Plus 10 MW Baseload Resource

	Total	Cost/Mwh	Change in total cost from preceeding year
2013/14	37,911,320	101.2	
2014/15	35,081,567	93.2	(2,829,753)
2015/16	34,998,256	92.5	(83,311)
2016/17	34,950,732	91.6	(47,524)
2017/18	39,918,293	103.6	4,967,561
2018/19	40,250,631	103.6	332,338